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COAL DEVELOPMENT:

Collected Papers

Volume I

Papers presented at
Coal Development Workshops in
Grand Junction, Colorado
and Casper, Wyoming

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Scott Fisher, Project Coordinator
Dave Books, Technical Editor
Linda Branch and Christy Fischer, Copy Editors

July 1983

INTRODUCTION

The collection of papers contained in these volumes and the parallel Coal Development Workshops held in Grand Junction, Colorado, and Casper, Wyoming, in 1982 are an indication of the seriousness with which the Bureau of Land Management (BLM) views the potential role of coal development in the West. The bureau has been very active in funding of coal development studies and research through its EMRIA (Energy Mineral Rehabilitation Inventory and Analysis) program from 1974 to 1982. Products from these efforts range from coal prelease tract studies, such as Pumpkin Creek and Red Rim, to studies on greenhouse testing of materials for evaluation as topsoil, and publications such as this. The potential impacts of coal development are very real, but with programs and leadership, such as the BLM EMRIA effort, the development of mitigating measures for several of the detrimental impacts can be accomplished.

The reader/audience, as I described it to the authors, includes BLM personnel, largely with natural resource backgrounds, who are responsible for making decisions relating to coal development. Equally important are the young people, both in and out of the academic environment, who may find the volumes interesting and challenging.

The primary objective in the design and implementation of this project was to provide a broad collection of reference papers covering the resource and the socioeconomic actions/reactions related to the development of coal in the Northern Great Plains. It became very apparent early in the developmental stages of the project that a reference containing state-of-the-art information for each subject area identified would constitute a significant contribution for both the specialist and land manager. Currently, much of this type of information is found widespread in the literature and needs constant revision to reflect research findings, actual data, and field applications or reactions. A second objective was to stress the interdisciplinary nature of dealing with resource developments while making a strong case for the development and implementation of land use decisions on a holistic basis. I strongly believe that the ecosystem approach must become the fundamental unit of land management. Parallel to that, socioeconomic concerns have to be extended beyond the corporate dividend, per capita income or venereal disease rates for a county. In reality, man exists as a biological component of the ecosystem. Certainly, his scope of influence encompasses interactions between individuals, social groups, and the groups' economic and related development activities.

This collection of papers represents the work of some of the leading authorities involved in coal devlopment in the Western United States. Inclusion of papers by these authorities in this publication was based on each author's knowledge of his respective field and his ability to express those ideas in a workshop format. Nearly all the authors have had academic as well as field experience in their disciplines. The workshops proved particularily fruitful for these individuals because of the high levels of interchange between the disciplines during the workshops. The discussions carried well into several nights and those ideas are reflected in the content of some of the papers contained in these volumes.

It is my sincere hope that these documents will become the fertile ground for additional reading and professional development in the area of coal development rather than balast to prevent bookshelves from wandering away. Hopefully, with education and high-quality training efforts, the workshops, the land use and resource management decisions in the country will be upgraded. Most importantly, the bottom line is whether individuals care enough about the resources of our country to become knowledgeable and involved in the decision-making process.

Scott Fisher,
Project Coordinator
April 17, 1983

ACKNOWLEDGEMENTS

The insight and programmatic direction for the project via its inclusion in the budgetary process came from the BLM Washington Office--in particular such people as Ron Kuhlman, Lee Koss and Monte Jordan. Herb Runkle, who so ably directed the Denver Service Center Division of Special Studies, made both the project and my involvement possible.

Without the efforts of Dave Books, the excellent Helena-based (Montana) editor, and Linda Branch, formerly Technical Editor in the Division of Special Studies and now in Durango, Colorado, with the BLM, the volumes would not have seen the light of day. An enormous amount of work was done by Christy Fischer of BLM, Division of Resource Systems. She has very ably directed much of the publication efforts during the last part of the project. Valerie Schupbach and Carolyn Tarpley of BLM have put in a significant amount of time typing these volumes. Jeanette O'Neill, also of BLM, has helped with some of the proofing.

In addition, a wide range of individuals have supported the completion of the project. Ron Clark and John Baker salvaged the effort when contract typing became impossible. Faye Leonard handled a myriad of contract work related to the workshops and handbook program. Shirley McCulloch created the covers and most ably helped Christy in cleaning up some of the less than professionally done figures.

I express, once again, very grateful thanks to all those listed above for making completion of the project possible.

Scott Fisher,
Project Coordinator
May 19, 1983

TABLE OF CONTENTS

Volume I

COAL AND ENERGY DEVELOPMENT ISSUES: THE BROAD PICTURE

		Page
Energy Future of the United States: The Contribution of the American West	Arnold J. Silverman	3
Forecast of Coal-Based Synthetic Fuels	Arnold J. Silverman	39
Demand for Northern Great Plains Coal to the Year 2010	Arnold J. Silverman and John Duffield	53
Midwestern and Eastern Coal Development Perspectives	B. Thomas Lowe	87
An Overview of Coal Leasing, Mine Development, and Future Production in the Powder River Coal Basin, Montana and Wyoming	Jack C. Schmidt and James Boyer	123

THE COAL RESOURCE

Physical and Chemical Characteristics of Coal	Don Snow	159
The Fort Union Formation in Montana	John Brown	201
History of the Coal-Bearing Rocks of the Mesaverde Group in Northwestern Colorado	John Brown	217

COAL DEVELOPMENT AND ASSOCIATED RESOURCES: PHYSICAL

Comparative Impacts of Mine-Mouth and Offsite Coal Utilization	Law Engineering Testing Company & Stinnett Assoc.	241

		Page
Engineering Aspects of Surface Coal Mine Planning, Development, and Operation	Matthew J. Hrebar	301
BLM Air Quality Handbook for Surface Coal Mines	Morrison-Knudsen Company, Inc.	377
BLM Blasting Impacts Handbook for Surface Coal Mines	Morrison-Knudsen Company, Inc.	519
Overburden Reclamation at Coal Surface Mines in the Northern Great Plains	D. J. Dollhopf	589
Hydrologic Principles and Models Related to Surface Mining	David B. McWhorter	627
Overview of the Alluvial Valley Floor Regulatory Program	Jack C. Schmidt and David Nimick	691

SOCIOECONOMIC CONSIDERATIONS

Socioeconomic Impacts of Western Coal Development	Mountain West Research, Inc.	739
Federal Land Management in the Coal Areas of the Northern Great Plains	Wallace McCrae	785

Volume II

COAL DEVELOPMENT AND ASSOCIATED RESOURCES: BIOLOGICAL

Microelements and Their Role in Surface Mine Planning	Frank F. Munshower	807
The Soil Resource: Its Importance in the West and its Role in Coal Development and Reclamation	Scott Fisher and Paul Deutsch	845

COAL DEVELOPMENT AND ASSOCIATED RESOURCES: BIOLOGICAL (Cont'd)

		Page
Review, Evaluation and Recommendations for Premine Vegetation Inventories in Montana, Wyoming, Colorado and North Dakota	Richard A. Prodgers	985
Vegetation Inventories in the Fort Union Region	Joe C. Elliott	1061
The Importance of Riparian Vegetation Communities in Colorado, Montana, Wyoming and North Dakota	Steve A. Young	1087
The Role of Greenhouse Studies In Evaluating Soil and Geologic Materials as Plant Growth Media in Reclamation	Robert D. Heil	1165
Wildlife and Surface Mining Reclamation	Franz. J. Camenzind	1187

RECLAMATION PLANNING AND REGULATION

Problems in Reclamation Planning and Design	Frank F. Munshower	1287
Regulation of Coal Mine Reclamation in Montana	Brace Hayden	1309
Historic Development of Reclamation Standards in Colorado	Ed Bischoff	1321

TOOLS

Development and Application of Soil Resource Information Systems	Robert D. Heil and Caroline Yonker	1345
Natural Resource Applications of Remote Sensing	Joe C. Elliott	1375
Systems Analysis and Environmental Impact Statements	Michael H. Wilson	1395
The Plant Information Network (PIN) in Resource Planning and Decisionmaking	P. L. Dittberner and M. Olson	1431

COAL AND ENERGY DEVELOPMENT ISSUES: THE BROAD PICTURE

ENERGY FUTURE OF THE UNITED STATES:
THE CONTRIBUTION OF THE AMERICAN WEST

by

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INTRODUCTION

Of the world energy pool--whether it be radioactivity of the earth, geothermal heat, the sun's solar energy, or energy produced by man through combustion--man's activity produces only a relatively small fraction of the total energy available. If we compare the energy that man produces by burning hydrocarbon fuels to the energy lost from radioactivity or dissipated by the tides or through geothermal heat losses, it is clear that the internal energy loss of the earth, which we are not capturing today, is on the order of four or five times the amount of energy that man produces each year (Table 1).* There are four orders of magnitude between the amount of solar energy that falls on the earth's surface over the course of a year and the amount produced by man. In fact, 10,000 times more energy falls on the earth's surface (in solar energy) in the course of a year than man combusts in all of his societal activity.

Although this is an interesting fact, it does not help us solve our short- or immediate-range energy problems, because solar energy is so dispersed and so difficult to convert to useable form that it will be long into the 21st century before it makes a significant impact on total energy use. The energy that man uses and will use for the rest of this century and well into the next can best be described as traditional or conventional energy: coal, oil, natural gas, and uranium, with oil shale potentially an important contributor after the year 2000. If one identifies those energy materials--what we call reserves--that can be recovered in today's economic climate and those materials that may eventually be recovered sometime in the future, and add them up, the balance turns out to be as follows: Most of the available energy in the world today is tied up in coal; indeed, almost half of the energy we will ever recover is also in coal resources (Table 2). So in the United States, as well as worldwide, coal provides most of the energy that is recoverable from the earth's crust. If uranium is used through a breeder-reactor system, in which the technology produces fuel as it produces electricity, we could extend the life of known uranium resources by about 100 times, and the total amount of uranium energy recoverable could be as much as that produced from coal. The amount of energy available from oil and natural gas--the two other traditional fuels used today--is only a small fraction of the amount available from coal and uranium. In fact, it is two orders of magnitude less. Oil shales, which are hydrocarbon-bearing marly or carbonate rocks, could eventually produce a significant amount of energy--

---

*Earth's interior is produced by radioactive decay and manifested by geothermal gradients. However, it is only 0.01 percent of the solar energy; in fact, it equals only 48 minutes of solar radiation striking the entire Earth. Even the total reserves (including undiscovered ones) have energy equal only to two days of solar radiation on the Earth. (The unwary reader might conclude that solar energy offers a free ride with respect to supplies of oil, gas, and coal.) However, in order to match the rate of fossil energy use, all of the sun's energy that reaches the Earth's surface within an area of 100 by 100 km near the equator would have to be captured. Moreover, at present, solar energy is much less efficiently converted to electricity than is fossil fuel energy.

TABLE 1. ENERGY PRODUCED FROM FOSSIL FUELS COMPARED WITH EARTH'S ENERGY FROM CERTAIN OTHER SOURCES

Energy	10^{20} Cal/Year	(10^{12} Watts)
Combustion by man (from Fossil Fuels)		
Crude oil and NGL	0.31	(4.1)
Natural gas	0.12	(1.6)
Coal	0.21	(2.8)
Total	0.6	(8.0)
From Other Sources		
Dissipated by tides (earth, water, air)	0.2	(2.7)
Radioactivity of earth (if like chondrite)	2.5	(33.0)
Geothermal losses of earth	3.2	(42.0)
Solar energy at earth's surface	6,500	(86,000)

TABLE 2. U.S. RECOVERABLE RESERVES AND RESOURCES OF ENERGY MINERALS

Mineral/fossil fuels	Recoverable reserves[a]	Potentially recoverable resources[b]
Coal	6,034	79,365
Oil (including natural gas liquids)	201	466
Natural gas	233	495
Oil shale	0	13,200
Uranium (from light water reactors, once-through fuel cycle)	247	680
Uranium (from breeder reactors)[c]	25,000	84,000

[a] Recoverable reserves are those specifically identified resources that can be extracted economically with existing technology at prevailing prices.
[b] Resources include all deposits known or believed to exist in such form that economic extraction is currently or potentially feasible.
[c] Assumes recovery of 70 percent of the energy content of natural uranium, plus 12,000 quads available from depleted uranium tails stockpile.

Source: CONAES 1979.

about a fifth or a fourth that of coal--but again, oil shales are relegated largely to 21st century use.

NATIONAL ENERGY PICTURE

Recognizing the petroleum, natural gas, coal, and a small amount of uranium are the major suppliers of energy in the U.S. economy today, one could ask why we cannot rely, over the long-term, on oil and gas to carry us through to a solar economy in the 21st century. The answer to that question rests upon the amount of oil and gas available for recovery. If you look at the oil reserves known to be contained in the U.S. and the amount of potential oil resources that may eventually be recovered within the U.S., we only have about 100 billion barrels of oil left (Table 3). Other economic and political entities in the western market, including the Arab states, could produce another 1,000 billion barrels; the centrally planned economies of eastern Europe and Asia could ultimately produce about 500 billion barrels. So the amount of petroleum that we might eventually recover from continental and offshore deposits in this country constitutes approximately 7% or 8% of the total petroleum available in the world (CONAES 1979).

Suppose, however, we engage in a scheme of developing all the petroleum supplies that we can find in the U.S., wherever they may be, as quickly as possible. How much petroleum might we recover? If we ignore environmental controls, open up Federal lands without regard for rational land management practices, and create all of the inducements for exploring for oil that the petroleum industry says are needed to stimulate more exploration and development, what could we expect to find and produce? We might be able to modestly increase the total amount of oil produced from a little over 100 billion barrels to about 150 billion barrels (Table 4). If we threw environmental concerns and planned development to the wind, we might be able to increase the total amount of petroleum recovered from the U.S. by about 20% to 25%. The U.S. uses about 5 billion barrels of oil a year, so the increase of approximately 25 to 30 billion barrels of oil in production would only increase our oil supplies (relying strictly on domestic sources) by about 6 years.

In addition, if we tried to produce that petroleum in any way that took cognizance of the total amount available and maximized output by efficient production methods, the domestic petroleum supply would still gradually decrease year after year over the next 30 years (Table 5). Even finding all of the petroleum that might be producible in the U.S. by throwing investment caution to the wind and environmental controls in the garbage can, and providing all the additional economic incentives that some think are needed to encourage oil and gas exploration, we would still be faced with diminishing amounts of domestic oil production each and every year.

The picture for natural gas is very much the same. The total amount of producible natural gas contained within the U.S. is only 10% of the total amount believed to be contained worldwide within the rocks of the earth's crust (Table 6). If natural gas exploration increased under an enhanced national commitment, we might be able to expand the total amount of gas

TABLE 3. U.S. AND WORLD RECOVERABLE RESERVES AND ESTIMATED RECOVERABLE POTENTIAL RESOURCES OF CRUDE OIL AND NATURAL GAS LIQUIDS

Location	Crude Oil			Natural gas liquids			Total		
	Recoverable reserves	Potentially recoverable resources	Total	Recoverable reserves	Potentially recoverable resources	Total	Recoverable reserves	Potentially recoverable resources	Total
				Billions of barrels					
U.S.	31.3	76	107	6.4	10	16	37.7	86	124
Other market economies	510	537	1047	66	70	136	576	607	1183
Centrally planned economies	101	350	451	13	45	58	114	395	509
World total	642.3	963	1605	85.4	125	210	727.7	1088	1815
				Quads (10^{15} Btu)					
U.S.	175	426	601	26	40	66	201	466	667
Other market economies	2856	3007	5863	266	282	548	3122	3290	6412
Centrally planned economies	566	1960	2526	53	181	234	619	2141	2760
World total	3597	5393	8990	345	503	848	3942	5897	9839

*As of December 31, 1976.
Source: CONAES 1977.

TABLE 4. U.S. PETROLEUM RESERVES AND RESOURCES

Scenario	Recoverable reserves		Potentially recoverable resources		Total recoverable resources	
	(10^9 bbl)	(quads)	(10^9 bbl)	(quads)	(10^9 bbl)	(quads)
Business as usual	38	201	86	466	124	667
Enhanced supply	42	222	94	509	136	731
National commitment	48	254	107	580	155	834

Source: CONAES 1979.

TABLE 5. U.S. PETROLEUM PRODUCTION TO 2010*

Scenario	Quads per year 1975	1985	1990	2000	2010
Business as usual	20	18	16	12	6
Enhanced supply	20	21	20	18	16
National commitment	20	21	21	20	18

*Table 5 illustrates that according to these estimates and under present trends crude oil production will decline steadily from now through 2010, although effective national policies could hold domestic production reasonably constant. According to these estimates, there are no policies that will increase significantly domestic production.

Source: CONAES 1979.

TABLE 6. U.S. AND WORLD RECOVERABLE RESERVES AND ESTIMATED RECOVERABLE POTENTIAL RESOURCES OF NATURAL GAS

Location	Recoverable reserves	Potentially recoverable resources	Total
		Trillion cubic feet	
U.S.	216	485	701
Other market economies	1200	2692	3892
Centrally planned economies	824	2000	2824
World total	2240	5177	7417
		Quads (10^{15} Btu)	
U.S.	233	495	716
Other market economies	1225	2750	3975
Centrally planned economies	841	2140	2881
World total	2299	5385	7572

Source: CONAES 1979.

to be produced by about 20% (Table 7). That 20% expansion turns out to be approximately 150 quads of energy, which would only extend the supply of natural gas for a period of 10 to 15 years. Although this indicates that the long-term expectation for greatly increasing the natural gas and oil supply is not very good, it might be possible to continue the current levels of production for another 20 years; we might find 15% more oil and 20% more gas than we currently expect if the oil and gas industry makes a very much larger annual exploration and capital investment.

Data for the last 10 years (1970-1980) show that oil and natural gas reserves have fallen precipitously during that period, even though the industry has been drilling many more wells (Table 8). Since the Arab oil embargo of 1973, reserves of oil and natural gas have declined steadily, even though in 1980 almost three times as many oil and gas wells were drilled as in 1970, amounting to about 250 million feet of drilling. That is an enormous expansion of the industry--nearly threefold in 10 years. It is far more than a threefold increase in dollar investment, because the deeper the well, the more expensive it is to drill. What this means is that oil and gas are becoming more difficult to discover and more expensive to recover; in fact, we are losing the challenge of maintaining our current reserves, to say nothing of adding to them for the future.

Oil products and natural gas are such generally used and convenient commodities that, given the organization of our economy, we have great difficulty in reducing use except through short-term rising prices and long-term national conservation policies. If we look at possible demand for oil and gas in the year 1995 in terms of world requirements and sources, it becomes clear that over the next 15 years, the West will become more dependent on imported oil, particularly Arab oil and more specifically, Saudi Arabian oil (Table 9). This is because the Middle East countries control the major sources of known oil in the world today and will continue to do so for at least the next 20 to 30 years when their reserves will begin to run down. And, by any measure, if we are going to be an oil and gas-using country for the next 20 to 30 years, it entails us to be dependent upon OPEC to supply a substantial share of the energy resources we demand. The level of that reliance depends on the actual level of demand. Under the most pessimistic of circumstances, in which the world is not conserving but is expanding its use of oil at a rate of 4% to 5% a year, we will be forced to rely on Saudi Arabia for almost 40% of the oil used in the market economies of the West (Table 9).

But oil and gas are not the only resources that we use in abundance. We also use coal extensively and are bound to use more of it in the future. We have a very large supply of coal, which constitutes the largest single energy source in the world today. It has been estimated that the proved reserves and undiscovered resources of coal in the U.S. amount to well over 3 trillion tons and that coal resources throughout the world total more than 11 trillion tons, a magnitude difficult to comprehend.

TABLE 7. NATURAL GAS RESOURCES AND RESERVES AS AFFECTED BY SCENARIO CONDITIONS*

Scenario	Recoverable reserves	Potentially recoverable resources	Total recoverable resources
Business as usual	221	495	716
Enhanced supply	244	543	787
National commitment	267	592	859

*In quads.

Source: CONAES 1979.

TABLE 8. SEARCH FOR OIL AND GAS

Year	U. S. oil reserves (billion barrels)	U. S. gas reserves (trillions ft^3)	Oil and gas wells drilled (thousands)
1970	39.0	290.8	28.1
1971	38.1	278.8	25.9
1972	36.3	266.1	27.3
1973	35.3	250.0	26.6
1974	34.3	237.1	31.7
1975	32.7	228.2	39.1
1976	31.0	216.0	41.5
1977	29.5	208.9	46.5
1978	27.8	200.3	48.5
1979	27.1	194.9	51.2
1980	NA	NA	62.7*

NA=Not available.
*From Petroleum Information Service.

TABLE 9. ESTIMATED REQUIREMENTS FOR WORLD OIL PRODUCTION THROUGH 1995 UNDER VARYING ASSUMPTIONS.[a]

	1975	1985	1995
Optimistic Case			
Total world production	111.2	171.4	207.7
Total of market economies (production)	87.8	131.0	153.6
OPEC	54.7	81.2	90.3
Arab	33.5	56.6	67.0
Saudi Arabian[b]	13.7	27.9	35.1
Share of market economies	Percent		
OPEC	62.3	61.8	58.4
Arab	38.2	46.1	43.4
Saudi	15.6	21.3	22.8
Middle Case			
Total world production		174.9	216.7
Total of market economies (production)		134.5	162.6
OPEC		88.9	106.7
Arab		61.2	82.0
Saudi Arabian[b]		33.1	50.9
Share of market economies	Percent		
OPEC		66.1	66.8
Arab		45.5	50.4
Saudi		24.6	31.3
Pessimistic Case			
Total world production		176.5	222.0
Total of market economies (production)		136.1	167.9
OPEC		95.0	124.2
Arab		67.7	96.0
Saudi Arabian[b]		40.2	66.5
Share of market economies	Percent		
OPEC		70.0	74.0
Arab		47.9	64.2
Saudi		29.5	39.6

[a] In quads per year.

[b] Production assumed to equal output needed to meet demand of market economies.

Source: CONAES (1979).

Most of the coal that is consumed produces electricity, so total coal demand is tied closely to the growth rate of electricity use. In the U.S. a number of demand scenarios are possible. Electric power consumption may grow at very modest rates, something on the order of 1% to 3% a year, or perhaps even less. Or growth may be as high as 4% or 5% a year but still below the historic highs of the 1960s and early 1970s. It is this critical difference between a low growth rate (of 1% or 2% a year) and a high growth rate (of 4% or 5% a year) that will determine the total tonnage of coal mined or used in the U.S. over the next 20 or 30 years, as well as the share of that total mined from the Northern Great Plains (NGP) and other western coal fields.

A recent Office of Surface Mining study (Silverman 1982) that defined the scope and size of the NGP coal market confirmed that this market is overwhelmingly sensitive to a single parameter: the electric energy growth rate projected for the market area. Table 10 presents some tentative scenarios for coal market levels as a function of growth rates and interfuel substitution. These scenarios suggest a very important point: The total amount of coal-derived energy from the NGP that we will use in the year 2010 depends almost exclusively on the electric growth rate. At very high growth rates, we will use very large amounts of coal from the NGP, regardless of how much nuclear, oil and gas, or hydropower energy is available. By the year 2010, something on the order of 700 or 800 million tons of coal annually will be needed if the growth rate of electricity demand is relatively high, say 4% to 5%. But if, as seems likely, the electric power growth rate decreases significantly from the 7% to 8% per year characteristic of the past 20 years to something like 2% and 3% per year, the amount of coal required from the NGP in 2010 will be only slightly more than the amount demanded in 1990. The estimates for coal coming from the Powder River region are about 200 million tons a year by 1985 and between 200 and 300 million tons in 1990. As U.S. coal consumption grows to something like 1.2 to 1.3 billion tons by the year 1990, the West, and particularly the Powder River Basin, will be asked to contribute between 200 and 300 million tons of coal per year, although the long-term picture (discussed in a later section) may be quite different. As mentioned earlier, the critical factor in determining how much coal comes out of the NGP is not major nuclear power development, a phase-out of oil and gas for electric production, or new hydropower generation, but is primarily the growth rate of electricity demand within the NGP market area.

The best estimates of growth rates for coal production in the U.S. (based on a national average of 4% to 5% annual growth in electricity demand) between 1985 and the year 2000 indicate we will use a billion tons of coal in 1985, between 1.2 and 1.3 billion tons a year by 1990, 1.6 to 1.7 billion tons a year by 1995, and somewhere around 2 billion tons of coal by the year 2000 (Fig. 1).

NATIONAL ENERGY FUTURE

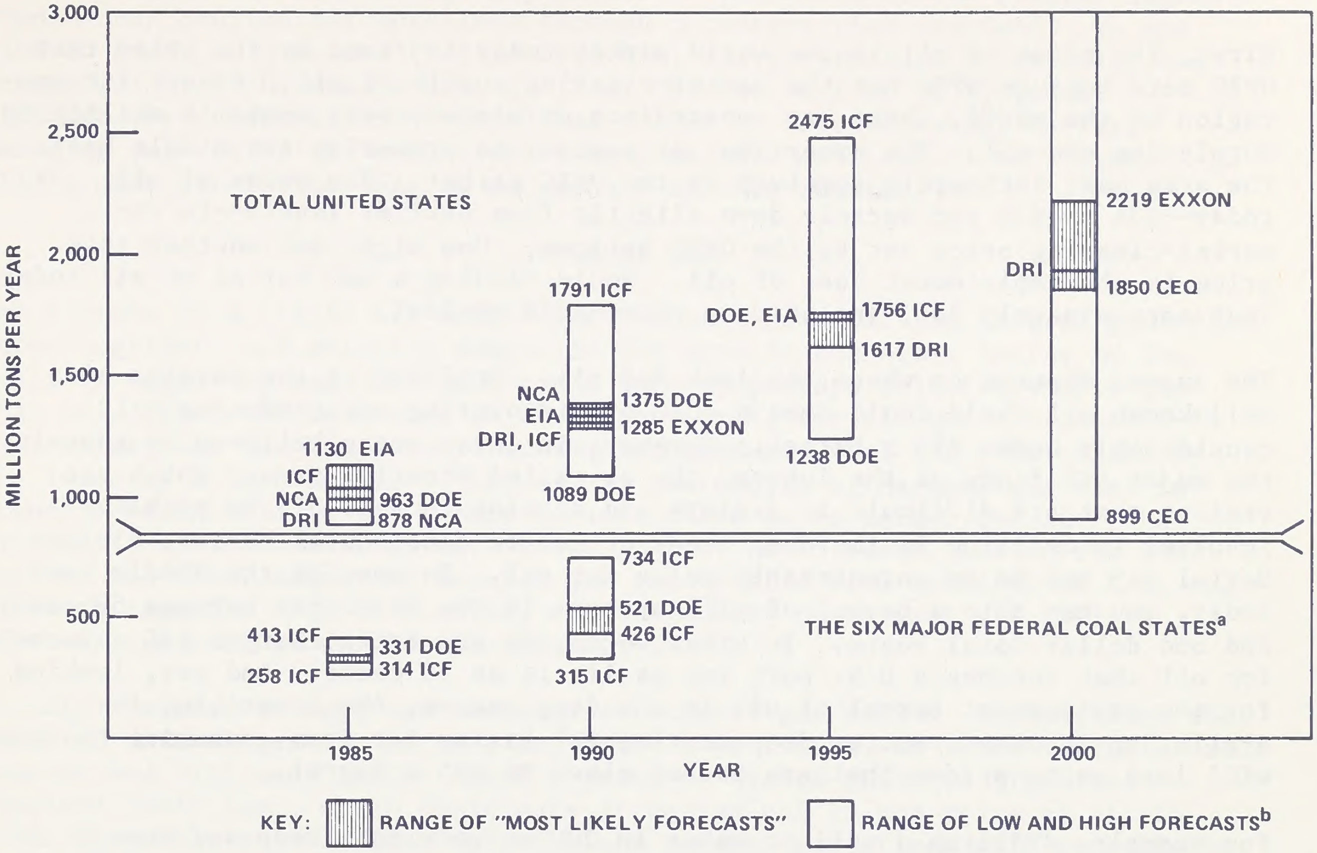
This introduction to the data base for energy consumption in the U.S. suggests that several features characteristic of the energy industry may have some long-term implications for our energy future.

TABLE 10. SCENARIOS FOR COAL MARKET LEVELS

Forecast	1980	1985	1990	1995	2000	2005	2010
ORNL-SLED							
Variation 1 *	85,964	246,585	302,974	563,644	901,248	1,168,841	1,377,501
2	89,835	149,668	184,623	284,061	412,485	494,828	588,905
3	84,838	221,452	273,364	494,030	777,651	963,798	1,176,469
4	89,835	141,842	165,653	244,619	346,711	417,449	498,267
5	85,964	173,820	210,724	371,702	535,462	657,262	796,417
DOE 1979 ARC							
Variation 1	84,415	181,821	174,558	299,196	455,996	545,391	648,514
2	89,887	131,999	136,921	190,492	255,261	295,104	341,475
3	83,842	170,855	162,019	278,432	425,202	507,512	597,061
4	89,887	124,602	127,980	175,602	233,004	263,725	297,147
5	84,415	136,829	143,687	211,361	292,908	338,496	393,961

*Figures in 1,000 tons of Northern Great Plains Coal.

From Silverman et al. 1981.



CEQ	COUNCIL ON ENVIRONMENTAL QUALITY	EIA	ENERGY INFORMATION ADMINISTRATION
DRI	DATA RESOURCES, INC.	ICF	ICF COAL ELECTRIC UTILITY MODEL
DOE	DEPT. OF ENERGY NATIONAL COAL MODEL[c]	NCA	NATIONAL COAL ASSOCIATION

[a] COLORADO, MONTANA, NEW MEXICO, NORTH DAKOTA, UTAH, AND WYOMING.

[b] INTERMEDIATE HIGH AND LOW FORECASTS FROM THE VARIOUS SOURCES NOT SHOWN.

[c] DOE'S 1980 PRELIMINARY PRODUCTION GOALS ARE SHOWN HERE RATHER THAN THE FINAL GOALS BECAUSE THEY ARE MORE COMPARABLE WITH OTHER PRODUCTION FORECASTS.

Figure 1.--Demand and production forecasts for the United States: 1985-2000 and the six major Federal Coal States:[a] 1985-1990.

Source: Office of Technology Assessment. 1981.

First, the price of oil in the world market today is fixed by the price that OPEC sets because OPEC has the market-clearing supply of oil. Except for one region of the world, there are constraints on almost every nation's ability to supply its own oil. The exception, of course, is primarily the Middle East, the area most intimately involved in the OPEC market. The price of oil today--$34 to $36 per barrel, down slightly from earlier levels--is the market-clearing price set by the OPEC nations. One might ask whether this price is the replacement cost of oil. Would finding a new barrel of oil today cost approximately $35, including a reasonable profit?

The answer depends on where you look for oil. Drilling in the margins of a well-known oil field could mean a cost of discovering and producing oil considerably under $35 a barrel. However, in those areas believed to contain the major oil finds of the future, the so-called frontier areas, which are regions that are difficult to explore and develop because of the problems involved in drilling in the deep ocean or remote continental basins, $35 per barrel may not be an unreasonable price for oil. In most of the Middle East today, you can ship a barrel of oil anywhere in the world for between 50 cents and one dollar total costs. In other words, we are being charged $35 a barrel for oil that reaches a U.S. port for as little as 50 cents. And yet, looking for the replacement barrel of oil in the deep oceans, the Antarctic, the Arctic, or in other remote, deep continental basins far from consuming centers will lead us to prices that are indeed close to $35 a barrel.

For example, drilling a well in water 10,000 or more feet deep and then drilling 10,000 feet deep into the sediments would cost approximately $50 million. If that well could produce a thousand barrels of oil a day (a pretty good production rate), it would not be possible to recover the investment. The rate of interest on that $50 million, plus the principal payment, compared with the cash flow resulting from 1,000 barrels of oil a day, would not quite pay off the investment and leave a profit in a reasonable length of time. So in frontier regions like the deep ocean continental rise, it may be difficult to produce oil for $35 a barrel.

We should be able to maintain close to current levels of production for petroleum, at least through the 1980s, with some slippage in the 1990s, but we will begin to see a real weakening of our domestic petroleum availability by the year 2000. Although short-term disruptions in the supply of petroleum may occur, particularly from the Middle East, every president in the last 15 years--Nixon, Ford, Carter, and now Reagan--has reaffirmed publicly, and without equivocation, that Middle East security and trade relations are vital to our national interest, and we will use whatever force is required to defend the flow of oil from the Middle East to our shores and the shores of our allies. Thus, the policy and rhetoric emanating from the Executive Office for the past 15 years have provided the rationale for essentially assuring that we will go to war over Middle East oil if it becomes necessary.

I would like to also suggest that it is highly unlikely or rather, nearly impossible, to cut our foreign dependence on petroleum to any greater degree than we can provide for ourselves through a conservation dividend. We are tied to Saudi oil; we are tied to OPEC oil; and we are tied politically and economically to the Middle East at least for the next 20 to 25 years. Although the conservation dividend has proved to be substantial so far, reducing imports by 50% over 2 years ago, we will continue to rely greatly on Middle East oil for as long as we use oil in this country.

Natural Gas

The picture is a little bit better for natural gas. Oil and natural gas often occur together, and drilling deeper in the more inaccessible basins of the world in exploring for petroleum could turn up perhaps relatively more gas than oil. This has been true in the recent past, for the great expansion in oil exploration for the last 18 months has produced what has been called by the industry a "gas bubble"--that is, an oversupply of natural gas that is actually being held in the ground because there is no market for it. That oversupply will be short-lived; it may last 10 or 15 years, but in the 21st century the total amount of natural gas recoverable from continental U.S. and offshore deposits will be limited, and the supply of natural gas will be severely constrained around the year 2020.

In this respect our days are numbered as natural gas users. In addition, the price of natural gas is due to rise in the near future, as price controls are removed and will most likely reach a price of around $6.50 to $7.00 per thousand cubic feet, which would make it equivalent to the price of oil in terms of energy value. That decontrol of natural gas prices will probably be the single most important energy factor in lowering middle income standard of living in the next 10 years. The rise in price of natural gas in a few short years, from a home-delivered price of about 50 cents per thousand cubic feet (10^6 Btu) to a price close to $7 per thousand cubic feet, will probably provide the incentive for significant domestic and industrial conservation, as well as for the conversion to plentiful and cheaper coal.

Uranium

The price of uranium will remain about the same in the near term; it has been essentially steady for the last 24 months and might in fact decline somewhat in the near future due to the recent collapse of the uranium mining industry. That industry follows closely the recently declining nuclear power industry, which means that, at least for the short-term, uranium will be in plentiful supply (Table 11).

The availability of enough urnaium to feed the nuclear power industry should not be a serious problem for the next 20 years. One recent forecast (CONAES 1979) suggested that at the rate we were planning nuclear power development in the mid-seventies, the uranium supply was wholly inadequate, and the situation would reach crisis proportions by the end of the 1980s. This is no longer a worry, because in 5 years we have witnessed a 50% reduction in the nuclear

TABLE 11. RESERVES, JANUARY 1, 1980*

$/lb U_3O_8 cost category	Tons of ore (millions)	Grade % U_3O_8	Contained tons of U_3O_8
$15	113	0.20	225,000
$30	658	0.10	645,000
$50	1,271	0.07	936,000
$100	1,958	0.06	1,122,000

*Uranium reserves are estimated minable quantities. Losses due to processing may range from 5 to 15 percent.

From U.S. DOE, 1980.

power industry and we are, for the near term, oversupplied with uranium rather than undersupplied. But who can predict 5 years into the future?

Coal

Coal mine-mouth prices will remain steady in the U.S. for the next few years, following the rate of inflation and lagging behind oil and gas. Coal will still be the cheapest energy available. It is now one-seventh the delivered cost of oil and natural gas in energy terms. Consequently, there is an enormous incentive driving the economy toward the use of coal, particularly to produce electricity, but also to supply industrial energy needs and for export to other countries.

The continued growth in coal use, primarily generated by the demand from U.S. utilities, will lead us to double our current consumption around the year 2010. The rate of growth will be slower than it has been, but there will be growth, nonetheless. In addition, there will be a strong new export market for American coal overseas, particularly in the Pacific Rim area and in Europe. We will also see, wherever possible, conversion from natural gas and petroleum to coal in U.S. industries.

Coal's advantage, according to the energy industry, is that it has no supply constraints. Although we may not have abundant oil and natural gas in the next 30 to 50 years, we will not run out of coal for a very long time. Therefore, the constraints on supply are not those related to the physical commodity in the ground but are related primarily to our ability to mine, transport, and burn coal--and those are enormous potential constraints (see later sections on the impacts of coal development).

Synfuels

With the reduced Reagan commitment to the Carter program for synfuel development (which, as proposed, was the largest public works project ever embarked upon in this country and rivals only the MX in terms of scale of investment), the program will have almost no impact on fuel supplies until the 21st century--if, in fact, there is any real impact at all. However, synfuels can be chosen by this country to replace conventional petroleum and gas with synthetic liquids and gas, even though it is not the most cost-effective alternative. It is clearly, however, one alternative that could be chosen by this economy if significant subsidy is reestablished as Federal policy.

Energy Policy

With respect to current energy policy, a brief summary is in order before turning specifically to resources in the West. The Reagan energy policy is clear. There is an energy policy, perhaps better defined than the Carter policy, which is to let the market act more fully as a pricing and resource allocating mechanism. That is, get the Federal government out of energy policy as quickly as and wherever possible and turn it all over to industry, for the energy industry is the best allocator of energy in terms of quantity and price. Issues of equity are not addressed directly by the new policy. The best example of this policy is the Reagan administration's recent announcement that it will try to kill the Emergency Oil Allocation Act when it comes up for renewal in Congress this year. That act is one that empowers the government to allocate the amount and price of oil for different refiners and different consumers if there is an emergency oil cutoff at some point in the future, as there was in 1973. So the Reagan administration has suggested that because the bureaucrats allegedly botched the 1973 experience so badly, the government is incapable of managing the oil and gas industry even during short periods of acute disruption. One must remember, however, that it is an awfully difficult job to manage the allocation, transportation, and pricing of 6 billion barrels of petroleum per year from a single, centrally located office in government. Government lacked experience and cooperation in 1973-1974 rather than policy, goodwill, and ability to manage. Regardless, the Reagan "proposal" relies upon the invisible hand of the market to be responsible for allocating oil in times of crisis, natural gas in terms of basic need, and coal leases as a prime instrument of land managment in the West.

What else can we say about the near-term future of energy in the United States? By and large, there will be a steady rather than spasmodic rise in the price of hydrocarbon fuels as market forces dominate energy end use and as price regulation ends. When price decontrol is accomplished, oil and natural gas prices probably will rise at a rate very close to that of inflation, coal will lag somewhat behind, maintaining the present cost differential on an energy basis, and electricity rates, particularly from nuclear power stations, will rise faster than other energy forms. The demand for traditional energy resources--coal, oil, natural gas, and nuclear power--will grow more slowly than it did from 1950 to 1980, perhaps at rates closer to 1% to 2% a year, rather than the 7% and 8% per year that characterized the earlier decades. We will not see total energy growth reverse; that is, it will not get smaller, but it will continue to rise at a slower rate than it has in the past.

Energy Options

To uncouple the U.S. economy from hydrocarbons (natural gas, petroleum, and coal) or some form of synthetic fuel, we must begin to make substantial investments in other types of energy-generating capital equipment and conservation programs. In fact, we are not doing it. Most of the large energy-related capital investment in the U.S. today is being planned for hydrocarbon fuels and nuclear power. These plants will be with us for 20 to 40 years. By the year 2000 we will be generating almost all (over 90%) of our energy from hydrocarbon sources. Nuclear power plants have a 30- to 40-year life, so those put on line today will be around in the year 2020. The amount of nuclear power generation will be relatively small compared with the total energy load. Clearly, at the turn of this century, we will still be enormously hydrocarbon-dependent.

During the 1980s and 1990s, the Federal government may once again decide that national energy planning may have some merit and that long-term renewable resource and conservation investments must be introduced and encouraged on a continuing basis. It is just as likely, however, that government will conclude that we must develop, as fast as possible, the American synfuel industry and use synthetic gas and liquid hydrocarbons as the alternatives to declining conventional sources; that we must support a commercial breeder-reactor to extend the life of the domestic uranium supply; and that we rely predominantly on coal, synthetic fuel, and uranium/plutonium for a large part of the 21st century.

For our energy future to be different, a lot of factors, both political and economic, must change in this country. Before this government, or the governments following the Reagan administration, stop supporting the heavily capitalized, centralized and internationalized energy base of the U.S., some very dramatic political and economic changes must take place. Given the Federal movement to reinvest in the market place, intellectually and philosophically as well as economically, there seems to be little chance for conservation and renewable energy to be an important part of our energy future through the first half of the 21st century. "Soft" energy is not in our immediate future, and even with the possible constraints of international insecurity in energy supplies, to say nothing of persistent and intractable environmental problems, we will most likely choose a hydrocarbon and nuclear energy source for the next 50 years. Such energy systems encourage the oligopoly control of international energy markets. Such a future promotes and rationalizes the horizontal diversification of the energy industries, so that a single company can supply oil or gas, coal, uranium, geothermal energy, or synfuels, and balance their price and availability to promote corporate wealth and power. If uncoupling is to take place at some rate that could ultimately affect as little as 25% of the U.S. energy industry by the year 2000, and hopefully as much as 50% of that demand by the year 2050, then we must see a dramatic change in current policy in the next two decades.

The West is a storehouse of the traditional energy fuels that we use. It is the major producer of uranium in the world and accounts for 95% of all uranium used in this country. Wyoming and New Mexico will continue to be the major world suppliers of uranium for years to come. The West produces 12% of U.S. coal and by the year 2000 it could produce as much as 30% of the U.S. supply. Perhaps with a major synfuel investment after the year 2000, the West may produce as much as 50% to 75% of the oil shale and coal-based synfuel energy developed in the U.S. In terms of conventional oil and gas, the West has a more modest future. The great hope of oil and gas production in the Overthrust Belt of the Rocky Mountain Front and in the deep intermountain valleys of the Basin and Range have perhaps been overstated in terms of their potential ability to yield oil and gas. Although some producing sites will be developed from both of these environments, this development will probably have a very small impact on a total demand of 13 to 15 million barrels of oil and nearly 70 billion cubic feet of gas per day.

Even if we are modestly successful in exploring the Rocky Mountains, the supply will most likely provide only a very small part of the oil and gas consumption that will occur in this country by the year 2000. In addition, the search for oil and gas in the Great Basin and the Overthrust Belt has conflicted with the lifestyle and environmental values of the region. This conflict may, on the one hand, constrain the availability of oil and gas from the West while preserving the last vestiges of wilderness on the other. The struggle for exploration rights in the Bob Marshall Wildreness is the kind of struggle that may be fought every year for the next few decades in the American West.

The other major problem related to oil and gas development in the West is that oil and gas production expansion (even a modest expansion) and the shift of oil and gas markets to the West (with a shift in population to the Sun Belt and the Mountain Belt) will create a demand to open new refineries. We have not built a new oil refinery in the U.S. for a number of years, and any new refinery that is built will in all likelihood be located in the West. Along with oil shale and coal synfuel plants and coal-fired power plants, oil refineries present the third type of major energy facility that will ask to be accommodated in the West.

The West contains a third to a half of national coal reserves, and the problems associated with their development are commonly known. They involve decisions related to mine permitting, adequate reclamation, protection of surface and underground water quality and quantity, the impact of energy development on the local economy and political structure, supporting investments by State and local government, and a host of other issues. More specifically, then, "where to mine" is the problem of the unsuitability of some lands for mining due to environmental and reclamation constraints; "at what rate should we mine" is the problem of the socioeconomic impact of rapid industrialization on small agricultural communities; "should we mine for conversion at the mine site or for export" is the problem of pollution impact on water, soil, air, and other living resources; and "at what rate to tax and for what purpose and at what place in the energy cycle" is the tightrope that we walk between enlightened self-interest and greed.

What is the energy future of America in the 21st century--at least in the first half of the 21st century? More than likely it is the future of coal and uranium, the future of synfuels, and the future of a commercial breeder reactor. Those two commodities, coal and uranium, can be abundantly supplied by western resources but not without enormous environmental and economic impact. The nature and size of that impact will be the focus of a long struggle between industrial market forces and conservation and environmental concerns. The opportunity for successful accommodation of coal and nuclear development in the West, as it is adapted to the traditional western lifestyles and economy, lies in defining and controlling the appropriate technology by which coal and uranium will be mined and used and in controlling the rate of expansion and development of the resource base. The struggle will center on what technology to allow in, at what rate, and where, rather than whether or not coal and uranium will be mined and used.

To alter this view of the future would require the demonstration of a very high level of political democracy among Americans in the future energy decisions of this country. Such a political democracy must develop an energy policy, planning, and implementation; aimed at consumer flexibility, lowest costs, renewables where appropriate, and a major investment in conservation. The alternative--greater emphasis on coal and nuclear power--will result in concentration of fuel supplies in fewer and fewer hands, higher prices, lack of fuel or energy choices, and a languishing renewable and conservation program.

ENERGY IN THE WEST: COAL

Coal is clearly our most abundant commercial energy source at present, and it is distributed throughout a large number of Appalachian, midcontinent, Rocky Mountain, and Great Plains States. We find in these regions large commercial deposits of coal containing enough energy to provide for most of our needs for a very long period. However, the form that they come in, along with the appropriate technology available for their recovery from the earth and their conversion to energy, provide the greatest challenge in expanding the use of coal.

The complex organic/mineral solid of varying energy content and subtle chemical differences finds its most abundant industrial use in generating electricity and producing metallurgical coke for reduction furnaces. The future worldwide growth of the coal industry depends on the introduction of efficient and clean-burning facilities for the generation of electricity and the technological direction and rate of expansion of synthetic fuels from coal.

Coal gasification and liquifaction, fluidized bed combustion, efficient particulate and gas scrubbing systems, and magnetohydrodynamics (MHD) provide the long-term linkage to markets for coal. Interestingly, the rank, grade, chemistry, and energy content of the coal resource base is of less importance to its future commercial use than are the conditions of economic infrastructure in the energy business and the environmental setting for coal mining and use. For example, thickness and continuity of seams, depth and character of overburden, unit train contract price, distribution and availability of water, air pollution control technology and ambient air standards, and mining recovery method will be the first order of concern in a future coal economy.

Coal in the National Setting

Underground mining will continue to have an important role in coal production in the Appalachian and midcontinent States. In these areas, deeply buried coal beds are mainly accessible through underground entry. These beds are relatively thin compared with the western coal seams, usually averaging 3 to 6 feet, but many fields have a high degree of continuity, a high Btu content and a moderate-to-high sulfur content. Underground systems encounter difficult and therefore costly mining situations, including the control of ground-water flow, acid mine drainage, disposal of waste rock, and the support of the mine roof and ground surface. These environmental and operational concerns escalate the cost of underground mining dramatically and, with increasing depth of mining in the future, they could become even more important than traditional economic controlling factors in eastern and midcontinent subsurface mine production.

In contrast, western coal, because it is accessible from the surface, can be mined cheaply, efficiently, and rapidly. Coal reclamation problems, depending on geographic and climatic site, include the diversion of flow and quality of surface and ground water, the mining of subirrigated alluvial valleys, and the character and longevity of the vegetative cover. Although these are substantial problems, there is at least in the mining industry, enormous confidence that they can be solved to everyone's satisfaction. Eastern coal mining, however, although traditional to certain areas, will encounter some long-term problems as mining goes deeper and the economic and social support structure needed for a viable enterprise comes closer to the margin of sustainability. This is not to suggest that large, modern, efficient underground mines will not be opened in the future in both the Appalachian and midcontinent coal beds. Indeed, they will be the mainstay of the coal-fired baseload electrification system of the Eastern States and midcontinent, as well as of significant new developing markets for coal export to Europe and elsewhere.

Transportation Net

Transportation accounts for 50% to 60% of the delivered cost of coal to a utility today. Transportation costs are anticipated to grow considerably faster than mining costs in the future, particularly in the West where coal is transported by unit train to central and eastern U.S. utilities. The transportation net and its ability to deliver energy at the utility's door at competitive prices, given the chemical and physical nature of the coal, becomes the determining factor in identifying the markets for Powder River, Fort Union, and other coal fields of the West.

The alternative to the unit train system of transport in America, which is presently the dominant mode of transport, is shipment of coal by wire (in the form of electricity) or by coal slurry pipeline. Slurry pipeline transport has been shown to be competitive with unit train in the past and has, in at least one case, been the major instrument for lowering train coal costs in one part of the country. The major stumbling blocks for development of slurry pipeline systems in the U.S. are the need for pipeline companies to achieve eminent domain status, particularly in the crossing of rail right-of-ways, and in the need for water from areas in which water is in short supply and is therefore already completely allocated.

Moving coal by wire essentially offers the utility industry the option of shipping electricity rather than coal across the country. This decision is more likely to be based on whether baseload areas have attained air pollution standards than on the slight cost differential between wire and train transport. It is most likely that new power plants will be located in areas that are not now highly polluted or are distant from the center of markets for electricity and synfuels. Mine-mouth generation and conversion will probably be the central focus of capital expansion within the coal-related industries of the future. Although some coal for conversion will be shipped to areas where abundant natural resources, such as water are available for effective utilization, it appears now that a large part of the future synthetic fuel industry, particularly as it relates to coal, will be located in the East and West adjacent to the largest coal reserves of those particular regions.

Coal Conversion

The conversion of coal to electricity and synthetic fuels presents one of the most demanding and challenging site planning and decision-making processes that will face Americans. The enormous size of the investment of human, economic, and physical resources and the long-term impacts that accompany a major coal conversion facility not only change the immediate character of a region but also commit the region for decades, or perhaps permanently, to the effects of the particular conversion technology.

Coal's Future

It is now abundantly clear that the historic growth rate of energy consumption in all of its forms and uses will decline over the next 20 years. This is not to say that we will be using less energy in the year 2000, but that the rate of expansion, and therefore the rate at which new facilities, plants, mines, and corridors of transportation need to come on line, will be greatly reduced over that of the past 30 years. There will be growth in electric power consumption--estimated at 2% to 2.5% per year for the next 10 years--but perhaps falling to 1.5% to 2% by the turn of the century.

With anticipated increasing costs of liquid and gaseous fuels, industries capable of converting to coal will find an enormous economic incentive to do so. This shift has already begun in industries that can readily make the change, such as cement, chemicals, clay drying, brick making, and a few others. The growth of the industrial market for coal within the U.S. will provide but a small part of the total demand, yet on the local level, it can be important in sustaining a small- to moderate-sized mine and will help to alleviate the cyclic nature of coal resource pricing and production. Although we expect to see upward pressure on coal prices, the significant differential on an energy basis between the price of coal and oil or gas will probably remain stable over the next 20 years.

The two fastest growing and relatively new markets for eastern and western coal will be steam coal for export, particularly to Europe, the Pacific Rim, and the emerging less-developed countries (LDC's) of the world, and for the synthetic gas and liquids industry. Development of synfuels from coal will be greatly conditioned by the availability of Federal funding and market agreements that reduce the risk to the early investors within the synfuels industry. A continuation of the current administrative policy makes it highly unlikely that the synfuels industry will grow rapidly over the next 20 years, although by the year 2000 we should have some hands-on experience with as many as half a dozen synfuel technologies, perhaps two or three of which will be coal-based and the others oil shale. An industry of this size will not dramatically affect the total coal requirement in the U.S. by the year 2000, which (based on reduced utility growth) is estimated at between 1.4 and 1.8 billion tons per year.

On the other hand, the export market for both eastern and western coals has developed dramatically in the last few years. Coal buyers from all the industrialized nations and emerging LDC's of the world have been looking at the possibility of importing relatively high quality U.S. coal. Western coals, particularly from the Powder River Basin, look attractive over the long term to the Pacific Rim market. Powder River coal has been found in a recent study by Silverman (1982) to rank closely behind the Utah coal fields in required characterization and economic competitiveness within the Pacific Rim. The attempt by Japan, Taiwan, and others to diversify coal sources has led to negotiation for coals in the Rocky Mountain and NGP West, and a number of contracts are on the verge of being announced. For the most part, long-term economic encouragement for substantial export coal hinges on the ability to provide adequate coalhandling and shipping systems from both the east and west coasts of the U.S.

Such systems are today inadequate for the export tonnages that might develop by the year 2000. New coal ports are clearly needed, and older ones will have to be expanded. On the West Coast, in particular, it seems likely that new coal ports will be preferred over the dramatic expansion of the small-volume coal-handling facilities at Los Angeles and Long Beach. At least one new port is being developed in Washington along the Columbia River.

Eastern coal ports to move metallurgical coking and steam utility coals to European markets and perhaps to South America will probably be located in traditional coal ports in the Chesapeake Bay and adjacent regions. Here expansion can take place rather efficiently, and the availability of coal from the Appalachian fields should provide a long-term contracted coal source for the European markets.

Impact of Coal Development

The impact of coal development has been alluded to in prior sections of this paper. In summary, there are four important types of impacts related to coal exploration, mining, transport, and conversion.

Coal Exploration Impacts

Exploration impacts are perhaps the most tolerable and manageable of those associated with the coal cycle. Coal exploration entails a different set of assumptions and technologies than the search for oil, gas, metals, or other kinds of fuel and mineral resources. Because of the nature of coal beds, their stratigraphic and areal continuity, and their reasonable definable basins, platforms of deposition, and outcrop extensions, reserve definition through drilling can be provided far enough ahead of coal mining to provide the necessary lead time for mine plan development.

In the western States, where extensive exploration occurs in a downdip direction from the coal outcrops, the major impact relates to those properties that are subsequently abandoned or held for future development. In such instances, close spacing of drill holes in the process of identifying the thickness and character of the coal may so disrupt the shallow water aquifers that they can become breached and lose their ability to transport water for stock, wildlife, or domestic use. In fact, once a property is developed, it is commonly necessary to provide an alternate source of shallow water for stock and domestic operation, because the coal seam no longer provides an accessible intake area for downdip transmission of the fluid. Reclaimed coal spoils have yet to be shown to effectively replace coal beds as high quality sources of near-surface water.

The other potentially important environmental impact of exploration is in the access to the coal-bearing site itself. In remote or undeveloped areas, the moving in of drilling equipment needed to prove out the economic parameters of a potential coal field may cause severe surface disruption--a concern that also accompanies oil and gas exploration and to some extent that of hard minerals. Throughout much of the West, however, and certainly throughout all of the eastern coal fields, access to coal fields is generally available in current land use schemes. Outside of some of the Indian reservations and the margins of designated or potential wilderness areas, the problem should not be a serious one in the future of coal development.

Mining Impacts

Mining impacts, on the other hand, are the most prominent, long lasting, and potentially difficult to resolve of those in the coal cycle. The last 15 years have shown the development of a remarkably effective science and technology for dealing with a number of the older problems exemplified by abandoned mine lands in both the East and the West. New techniques, such as box cut and fill in the contour mining system, head-of-hollow of first cut, reconstruction of original contour and drainage, replacement of topsoil, rapid establishment of vegetative cover, manipulation of the restacked overburden material, surface manipulation of the spoils to form small catchment basins, and many others, suggest that enormous strides have been made in the resolution of some of the more serious environmental problems associated with coal mining. However, we have to remember that certain problems remain, both as carryovers from earlier mining periods and as a result of current mining strategies. They involve: (1) The support of the surface and the problem of surface subsidence in many of the eastern coal fields, and the universality of that problem anywhere underground mining occurs without adequate backfilling and stabilizing measures within the mine proper; and (2) the difficulty of long-term control of acidified mine water discharge, particularly in the eastern part of the U.S., which will continue to challenge our best scientific and technologic abilities in the years to come. The state in which we leave mined-out coal properties determines the long-term environmental problems related to acid mine drainage. For some properties, we may have no choice but to continually maintain a system of neutralization before adding mine waters to the surrounding systems.

In the West, the effectiveness of reclamation remains a prominent subject of discussion and research. Our reclamation experience is too short to pronounce once and for all that reclamation has been either successful or unsuccessful at the sites that have been disturbed. We have come to better understand the importance of local climatic factors in determining the potential for successful reclamation; however, we do not have the long-term studies necessary to understand the evolutionary trends that we have set in motion on reclaimed sites and to evaluate whether those sites will ever be self-supporting and productive in a way that equals or improves upon their original character. The reclamation required by Federal regulations and permitted by State agencies will play an enormous role in establishing standards of local usability for mined lands and the regional confidence that mining can be part of a sequential use of land that does not essentially destroy the productivity of those lands for wildlife and human use.

Transportation Impacts

The impacts of transportation in the coal cycle derive from one of the three major transport systems either now in effect or envisioned for the future--unit train transport, coal slurry, and the transmission of coal by wire (as electricity) from mine-mouth facilities to market centers. Transportation considerations also include synthetic fuels that might be fed into existing or newly constructed gas or oil pipeline feeders.

The building of any transmission corridor, whether pipe, rail, or wire, presents a series of problems, both natural and human, that are unique in part to the route chosen. Those problems involve the physical disruption of surface and near-surface water systems in springs and rivers, the pollution derived from the construction phase, the long-term physical and/or esthetic effect of the transmission corridor, the potential for accident or breakage of the transmission system thereby affecting nearby properties, and the receptiveness of the social and political community to the trespass of a large and permanent physical system. How best to weigh the social and economic costs and the efficiency factors of transportation corridors and to ameliorate the long-term concerns and impacts that such corridors produce is clearly a significant concern in the future of coal development. It appears that there is no easy choice in the matter of preferred transport systems since there is an argument to be made for each of them.

Often the choice is a matter of chance rather than design. Certainly one of the more important considerations related to the impact of transport corridors centers on the other major land users along the route and raises questions of conern about compatibility.

Coal Conversion Impacts

Lastly, but in many ways most importantly, the impact of conversion facilities--their siting, technology, drain on local resources, and impact on regional resources over long periods--provides one of the most important elements for evaluation and decisionmaking within the coal cycle. These elements are all the more difficult to evaluate because of the size and complexity of conversion facilities which range from standard steam electric-generating, coal-utilizing boilers to drawing-board versions of coal liquefaction and gasification facilities. The enormous potential impact of liquid and gaseous emissions, the utilization of surrounding natural resources (especially water and air), the social impact of the size and composition of the labor force upon small, often isolated, usually agricultural communities, and the enormous capital investment associated with such facilities--investments that can only be recaptured in 20- to 40-year operational schemes--suggest a long-term, generational impact that will clearly dominate the region in which such facilities are located. From the standpoint of the availability of scarce resources, such as water and clean air, these facilities are the primary factors controlling alternative industrial and agricultural development. These conversion facilities can, therefore, foreclose for a very long period alternative developments that may need quality air and water resources to function successfully.

With respect to the social infrastructure of small western agricultural communities and, for that matter, small eastern coal mining communities in West Virginia, Kentucky, Tennessee, and Pennsylvania, the siting of a large conversion facility would dramatically and permanently alter the character of those communities. Introducing a large, complex, expensive coal conversion technology into the community supplies it with a very different set of skills and expectations and creates a new set of population dynamics bound to create permanent change. In fact, introducing large energy-conversion facilities into traditional natural resource and agriculture-based economies eliminates the hope of maintaining a semblance of what once existed. In those environments where the impetus for siting major conversion facilities has been government support intended to provide working experience with that technology, the problems may be even more dramatic, if that technology proves to be difficult to manage and economically unsuited for commercial energy development over the next 20 to 40 years. Under these conditions, a boom-and-bust mentality can move so quickly through a cycle that all concerned will be adversely affected, and little or no time will be available to condition the local population to the normal functioning of this technology. Therefore, one can say that mining and conversion impacts on both the natural environment and on social problems are overwhelming matters of concern from the local to the regional level, because they shape the quality, character, and longevity of a region with respect to traditional activities and their interaction with new social and economic forms.

Production Structure

Coal mining in the West has had a long history, which is currently emerging into a new structure with an economic character unlike coal development in any other part of the country. We are witnessing the emergence of an industry in the West that is rapidly providing a standby hydrocarbon capacity for the traditional energy corporations; this evolution is described in detail in a paper by Jack Schmidt (Overview of Coal Leasing ..., this volume); therefore, I will not dwell on the direction and implications of that activity here.

It is important to note, however, that the size and structure of the western coal mining industry, particularly in the Powder River and Fort Union Basins, will be shaped to a large degree by the perceptions, resources, and chosen coal use of the traditional, large, multinational oil and gas corporations.

The small coal miner, so characteristic of the Appalachian east, and the medium- to large-sized traditional coal mining corporation characteristic of the midcontinent, differ significantly from the economic and marketing structure that has developed in the NGP coal fields and in other parts of the West.

Coal mining in the NGP is based on a number of coal characteristics that appear to have determined the level of coal development in the past 12 years and will continue to do so for the next 20 to 40 years. These characteristics are as follows: relatively young coal (Tertiary age), modest to low Btu value, thick seams (in places, thick multiple seams), a relatively shallow overburden, and low sulfur content. These characteristics inexorably drive a surface mining industry with relatively little waste rock to move and with coals that, if they no longer meet clean air standards without scrubbing, certainly provide lower cleanup costs to the utilities that use them. In addition, the high productivity of the mines themselves, the relatively low labor costs, and the more-than-adequate transportation net (unit trains for long hauls to the north-central and south-central parts of the country), have made the NGP the most rapidly developing and potentially prolific coal-producing area of the country.

Surface mines with units that can produce upward of 20 million tons per year for a given lease will rapidly become the rule in the NGP. These coals are ideally suited to the utility industry because of their sulfur, moisture, ash, and energy content, provided they can reach the boiler at competitive transportation prices. Such mines are highly efficient, with 30 to 75 tons per man day easily achievable with new mines. For the most part, these mines will be areal systems, although underground mines in Utah and Colorado, as well as the possible downstream development of in-situ gasification from certain coal beds, could provide alternative mining systems that will produce important energy tonnages. Western mines are operated with a small, skilled work force; can be run 24 hours a day, seven days a week; require a continuing haulage system from the mine so that storage does not become a problem at the site itself; and provide yields of from 20,000 to 250,000 tons per acre of mined land.

Given the current coal market, the cost of reclamation on a per-acre basis still remains in the realm of pennies per ton for some of the most prolific coal sites in the NGP. It is not cost so much as it is knowing what to do that becomes the critical limiting factor in effective reclamation at most of the NGP mining sites. This is clearly the case in desert climates on the southwestern Indian reservations, as well as on the public lands of southern Utah, Arizona, and New Mexico. Another critical factor in developing NGP mines of large tonnages and ready access to transportation was, until recently, the ability to attract large tonnage, long-term contracts for utility boilers close to load centers or within the coal-mining region itself. The character of this type of coal contracting and mine development has begun to change with the recent economic prominence and reserve position of major oil and gas companies in the NGP (see Overview of Coal Leasing...).

Coal Ownership

Within the NGP and some other western coal fields, the dominant ownership of coal has involved primarily the Federal government, with State and private owners playing an important but generally subsidiary role. Federal ownership of coal in places served from surface ownership provided one of the most difficult and contentious aspects in the development of the Coal Surface Mining and Reclamation Act of 1977. The Federal role in coal ownership, leasing, and development continues to be one of the most highly debated and important issues in determining the character of development of the NGP coal fields in both the Powder River and Fort Union Basins. Development of economically feasible mining units usually involves the ability to use one or more tracts of Federal coal, sometimes in concert with private or State holdings. Therefore, Federal policy with respect to leasing, as it affects the conditions of the lease, rates of development, royalties, taxes, and the use of other natural resources, becomes critical in pacing the rate of coal development in the NGP. This in turn dramatically affects the kind of coal markets that will be sought, whether coal will be converted locally or exported, the rate of conversion and character of conversion facilities, and whether water can or will be transferred interbasinally or intrabasinally. It is now clear that, at least within certain limits, Federal policy aimed at encouraging energy development, especially in coal areas, can provide the required impetus for new resource ventures.

Just as important, however, is the anticipation of what the downstream demand will be for energy, the form of energy preferred by the marketplace, and the willingness or ability to pay for that energy resource. In short to intermediate term, it is therefore uncertain that the widespread leasing of resources whose production becomes economically feasible well beyond the year 2000 makes good sense in the current energy market. Lead times are necessary for the development of any large, complex organization like a mine, and those lead times, as they attend to the requirements of environmental impacts and economic and social assessments, stretch out toward a decade before actual mine production begins. However, lead times of 30 to 40 years are clearly not required. The allocation of Federal resources to the private sector for potential development can be very expensive and will tend to move the resources into fewer and fewer hands and encourage price speculation in the initial leasing phase. Therefore, the argument that the State has its greatest return on investment through leasing all its resources in a completely open and competitive market is quite debatable; the program currently envisioned to dramatically expand lease holdings and resource positions on a competitive basis within the NGP may not be the most effective action that can be taken to expand coal production and protect alternate resource use.

Coal Development and Resource Conflicts

The unique character of the NGP grazing and agricultural lands, as well as wildlife domain, presents to the miner a distinct challenge. Surface areal mining will dominate NGP coal extraction, with a railroad, pipeline, or electric transmission corridor linking the mine site to the base load center. At the mine site itself, parallel reclamation and mining activity will provide an early baseline for evaluating the success of the reclamation plan. It is possible, therefore, to alter the initial plan or adapt the mining system to the alternatives needed to better ensure a high quality reclamation.

It seems clear that one very important land impact relates to the ability to restore, in some effective fashion, the subirrigated alluvial valleys that constitute the critical acreage in a successful ranching operation in the NGP. Although such reconstruction has yet to be demonstrated on site, much has been written and some thoughtful discussion has proceeded from what at least some feel are problems of manageable proportions, given the resources known to be available.

With regard to the social parameters of NGP development, much has been said about the potential compatibility and incompatibility of joining populations that derive their economic income from agriculture with those employed in technical and laboring jobs associated with energy production and conversion. There is clearly a changing dynamic in the areas of energy development in the Rockies and the Great Plains. That dynamic is not anywhere deemed successful, however; an emerging set of accommodation models, based on both ethnological and more traditional social science research, could help to provide a temporary understanding, if not accommodation, in these western communities.

However, evidence is mounting that certain activities are basically incompatible and that one cannot sustain traditional activities related to agriculture, recreation, and wildlife protection on lands that have been highly affected by the effluent of energy conversion facilities, by the dramatic increase and mobility of populations within the regions, and by the necessary communication and transportation infrastructure that develops from these energy centers. The effects cannot always be ameliorated or rationalized through the goodwill of front-end capital aimed at anticipating population problems, or even the continuing flow of State and local resources into the areas of impact through, for example, a coal severance tax. We may in fact find that the incompatibility is so great that coal-producing and coal-converting activities in a relatively small geographic area will effectively usurp the ability for all other economic and social systems to survive effectively. In other words, we have provided a site dedicated to energy mining and conversion alone. Unfortunately, we may not be able to recognize this until well into the economic stream developed at the site itself, so that an anticipated 25- or 35-year facility may not show until the 10th or 15th year the all-encompassing impact it will have on the local and regional environment.

Coal Market Cycles, Pricing, and Alternatives

Lastly, a word must be said about the consistent truth about energy resource development and utilization: It is an activity strongly characterized by cycles of increasing production and increasing prices followed by low production and declining prices. There is an acute attunement of energy availability and price to the economic rhythms of a nation. And although the short-term outlook for NGP coal development can only be described as expanding, at least to the year 2000, that expansion will not take place without some interruption of growth, short-term reversal of anticipated trends, economic disappointment, and social hardship that accompany all cyclic reversals in economic activity. Coal is part of the energy business and will be subject to the same uncertainties as other fuels.

In the euphoria of growth and with the wealth of rising coal sales and a highly sought-after resource base, the NGP region must also come to understand the ultimate role of conservation, renewables, and other nonhydrocarbon resources for fueling the energy demand of the nation. We cannot, however, expect the NGP to lead on this path independent of a national commitment to provide for this nation those alternatives in energy development that will be necessary for the economic and social activity of society in the 21st century. Such activity, such concern for the ultimate nature of our energy base, and respect for the environment in which those energy sources must be developed, will eventually dominate our planning for the energy future of America. We are still in a hydrocarbon-uranium age; these are prolific resources and ones that can fuel economic expansion in most of the industrialized, and in many of the lesser developed, countries of the world for a long period. But within a couple of generations we must have made our stand in designing and promoting the long-term energy flow that we expect to receive during the 21st century to support the activity of man on the planet Earth.

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FORECAST OF COAL-BASED SYNTHETIC FUELS

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INTRODUCTION

A national synthetic fuels program based primarily upon coal and oil shale has an intellectual history in this country going back to World War II. Its practical implementation during post-World War II years continually floundered upon cheap and abundant traditional oil and gas supplies in this country and abroad. The increasing dependence upon hydrocarbon fluids in America, together with reliance upon imports (especially from Organization of Petroleum Exporting Countries (OPEC)), declining exploration success within continental America, and relatively low prices controlled by Federal regulation, set the stage in the early 1970s for the rapid escalation of oil and gas prices for the remainder of the decade. This caused severe dislocations in the economies of most countries, a distribution of the flow of national wealth, and the emergence of new political realities for Western industrialized and emerging countries.

The themes of conservation and reduced dependence upon foreign imports of oil were to be part of the structure of a national energy policy for the United States. Through fitful policy and program starts and reversals in course, together with a tenfold increase in the price of gas and oil, this country and others succeeded in reducing imports in the last two years. At the same time, industry has generated a large gas bubble in the supply side structure of the gas industry and caused a temporary oversupply of oil triggering recent price reductions. Key causes of this change are the stimulation of exploration and some new discoveries, more rapid development of known fields, and reduction in use through conservation and a declining business cycle.

The long-term outlook for oil and gas supplies and their price is not cause for celebration. The events of the last two years were mainly an adjustment period by both the major world suppliers and consumers. Levels of production and the market price are rapidly moving into a long-term balance that promises a slower but steady increase in energy prices with a reduced worldwide level of economic growth. Demand for hydrocarbon fluids will rise again shortly, OPEC and eastern bloc transfers will grow but perhaps more slowly than in the past, and prices will rise to keep pace with levels of inflation and the replacement cost of oil and gas. There is, therefore, a strong and growing interest in synthetic fuels from oil shale and coal to supplement and stabilize the import markets and domestic production in the years ahead. The main determinant to the timing and structure of synthetic fuel development in the United States, as it has been for the past 40 years, revolves around the price of oil and guarantees for a new and costly industry that requires on-line production experience before long-term economic assessments and viability can be made.

To this end, Congress passed and President Carter signed the 1980 Energy Security Act (ESA), which identified a road to energy security through the development of a domestic synthetic fuels industry that could produce the equivalent of at least 500,000 barrels of syncrude per day by 1987 and 2 million barrels per day by 1992. The ESA recognized the need to protect the environment and to raise large capital resources to initiate a synfuels industry, so it mandated a Synthetic Fuels Corporation (SFC) to guide and assist private enterprise in organizing the resources needed to meet the production goals stated above. In addition, the SFC was to support a variety of fuel sources (coal, oil shale, tar sands, hydrogen from water, and biomass) as substitutes for traditional petroleum and gas and spread the initial industry support among the available production technologies and appropriate geographic areas.

To meet the goals of this program in the view of most knowledgeable observers would have required: an overwhelming reliance on first-generation, relatively inefficient technology; expedient environmental and construction planning; potential conflict with other resource allocations with prior recognition (especially water and air-quality standard designations), and a very heavy reliance on Federal funding and guarantees that promised to involve the public sector long after commercial experience with the first plants is achieved. Thus, some observers feared at least a repetition of the nuclear energy story and argued for market factors and environmental constraints to guide the level, diversity and timing of an American synthetic fuel industry. In fact, the Carter goals were much too ambitious even for an expedited program of synfuel development; with the Reagan Administration, energy policy has become part of a more general strategy for economic recovery--it emphasizes private sector investment; reduces Federal involvement except when Federal guarantees or regulations, research investments, or tax restructuring can promote a climate for long-term risk taking; decontrols fuel prices; and provides a more ready access to the resource base from which the synthetic fuels will be derived. Under the Reagan program, the SFC outlays will be reduced substantially in the next five years, and fewer planning and construction grants will be made than originally anticipated.

SYNTHETIC FUEL PROJECTIONS: NATIONAL

Detailed forecasts of a synthetic fuels industry size in the U.S. began in the mid-1970s and continue today. Two factors, at least over the next twenty years, constrain the total size and mix of the synthetic fuels forecast--the price of oil on the world market and the constraint that scarce water supplies, especially in the West, place upon the development of an oil shale and to some extent synthetic coal industry.

On the other hand, it is synthetic liquids that are most important in reducing our energy vulnerability through reducing oil imports and perhaps establishing a relatively cheap, strategic oil stockpile. With water a limiting factor in the oil shale fields of western Colorado, eastern Utah, southwestern Wyoming and northwestern New Mexico, syncrude from coal looks potentially attractive. However, this present technology is both first-generation and expensive (Lurgi process followed by catalytic synthesis), but it can produce methanol or Fischer-Tropsch liquids like diesel and gasoline. Synthetic conversion from coal in the richest of the Western coal fields may, however, also be constrained by water availability, especially if a large industry were envisioned beyond the year 2000, and restrictions on interbasin transfers and minimal instream flows are maintained.

World petroleum prices are difficult to predict; however, barring a war or radical political change involving most of OPEC (especially Saudi Arabia), oil prices will not rise as precipitiously nor to the relative extent we witnessed during the 1970s. Rather, as oil exporting nations learn by trial and error the extent price hikes can be absorbed by consuming countries without serious economic calamity and establish internal budget goals reflecting expected long-term cash flows, a world price and supply equilibrium will be established and maintained for the next 10 to 20 years. Oil prices will rise as a function of inflation, together with a premium for the replacement costs of oil. This latter cost will grow more important as physical limits of production become more obvious in the decades ahead.

On the other hand, alternative strategies aimed at extending world energy supplies, including conservation, renewables and perhaps synfuels, can slow the rate of world oil price escalation. Most observers suggest oil prices of \$50 to \$75 per barrel by the year 2000, with prices rising faster in the decade of the 1990s, even though world economic growth will slow perceptably near the end of the 20th century. By the year 2000, the key to continued development of a synfuels industry (based primarily upon oil shale and coal) rests with our ability to develop more efficient second-generation technologies that can maintain an economic advantage in production costs compared to traditional petroleum and natural gas occurrence. In 1981 dollars, it is expected that competitive technologies must hold synfuel costs to between \$25 and \$35 per barrel.

Under this set of assumptions, one can review past forecasts and present projections for both national and Northern Great Plains (NGP). Most past projections of synfuel development are predicated upon one very high and one rather low national energy growth rate, compared to the last twenty years. Levels between these extremes are arbitrary and tend to provide forecasters with more reasonable upper limits than does the very high rate, usually an extrapolation of past growth curves which have little meaning in the current and future set of energy supply and demand conditions.

Although actual growth rates are not provided in some forecasts, terms like "national commitment," "enhanced production," or "maximum credible implementation" present the high growth (5% to 8%), while "business as usual," "low range" and "low growth" present the other end at rates of 1% to 2.5% per annum.

1976 ERDA Forecast

In 1976, the Energy Research Development Administration (ERDA) presented a synthetic liquid fuels scenario that projected a maximum level 1 Mb/d (0.5 Mb/d shale oil and 0.5 Mb/d methanol) by 1985; 3 Mb/d by 1990 (1.5 Mb/d shale oil, 1.0 Mb/d methanol and 0.5 Mb/d syncrude); and 10 Mb/d by 2000 (4.0 Mb/d syncrude, 4.0 Mb/d methanol and 2.0 Mb/d shale oil). These projections had shale oil produced by the Tosco 11 method, methanol from coal by Lurgi gasifier coupled with methanol syntheses, and syncrude from coal by the H-coal process. Energy gain conversion ratios range from 0.6 to 1.3 in coal technologies and 1.6 for shale oil. Coal requirements for this forecast are from 50 mmt/yr in 1985 to 440 mmt/yr in 2000, using the average Btu value of NGP coal (using eastern coal values reduces the oil consumption by 25%). Within the NGP, levels of synthetic liquids production and coal requirements forecast for the same period were 0.185 Mb/d and 18 mmt/yr of coal in 1985; 0.7 Mb/d and 70 mmt/yr of coal in 1990; and 4.5 Mb/d and 225 mmt/yr of coal in 2000. This last value is 45% of the total national liquid synfuel forecast.

At the maximum levels of development projected in the year 2000, new water requirements in the NGP region would add from 1.4 mm ac-ft/yr to 3.0 to 4.0 mm ac-ft/yr in new obligations. The average low water value at Sioux City, Iowa, on the Missouri River is 6 mm ac-ft/yr. Therefore, in average low water years, the Missouri could be more than 65% depleted; in extreme years, the Missouri could be dry and conversion plants must shut down, or plants must store water or tap the ground water system to continue to operate.

CONAES, National Research Council, 1979

In a large and comprehensive study of nuclear and alternative energy systems calculated to the year 2010, a National Research Council committee forecast the substantial development of a synthetic fuels industry in the United States. The council suggested that oil shale development will peak out in the year 2010 at 3 quads per year (1.5 mm bpd production capacity) due to the constraints exerted by a limited water supply and water and air quality standards. Coal, on the other hand, was seen as having enormous potential and under three scenarios (Business as Usual, Enhanced Supply and National Commitment), forecasts for a national industry were made to the year 2010 (see Table 1).

Based upon the National Research Council forecast, an initial coal-based synfuel industry in 1985 would require between 30 and 70 mmt nationally, levels that will likely not be seen due to the slow start-up of the Synthetic Fuels Corporation. The 1990 forecast is for between 0.8 and 1.2 mmbpd of oil equivalent, requiring from 130 to 185 mmt/yr of coal. This level is almost coincident with the Carter Administration goals for 1990. By the year 2000, a National Commitment scenario raises the forecasted production significantly above the other two scenarios. Levels of production range from a low of 2.9 mmbpd of oil equivalent, requiring 450 mmt/yr of coal to 4.6 mmbpd of oil equivalent requiring 685 mmt/yr of coal. By the year 2010, synthetic coal liquids are dominant over syngas, and forecasts range between 5 mmbpd of oil equivalent, requiring 765 mmt/yr of coal, to a National Commitment forecast of 10 mmbpd of oil equivalent requiring 1.5 billion tons of coal per year. On all of the above calculations, the coal tonnage conversions used the values of the low Btu western coal. Use of eastern coals would reduce the numbers approximately 25%.

The Committee on Nuclear and Alternative Energy System (CONAES) forecast suggests that a significant coal synfuel industry cannot be put in place before the year 2000 regardless of the level of national effort. In addition, without a "national commitment," the synthetic fuel industry cannot replace fully foreign imports (assuming the current levels) much before the year 2010,

TABLE 1. CONAES COAL-BASED SYNTHETIC FUEL FORECASTS.

		Quads Per Year			
Scenario	Energy Source	1985	1990	2000	2010
Business as Usual	Synthetic Gas	0.3	1.3	3.5	4.1
	Synthetic Liquid	0.1	0.3	2.3	6.1
	Required Coal	0.6	2.6	8.9	15.3
Enhanced Supply	Synthetic Gas	0.5	1.7	3.5	4.8
	Synthetic Liquid	0.1	0.4	2.4	8.0
	Required Coal	0.9	3.3	9.0	19.0
National Commitment	Synthetic Gas	0.7	1.7	4.5	7.9
	Synthetic Liquid	0.1	0.7	4.7	12.9
	Required Coal	1.3	3.7	13.7	30.8

Source: CONAES 1979

if then. The constraints on an industry of this size will be examined in another part of this chapter.

1981 Energy Projections to the Year 2000 (U.S. Department of Energy)

Based upon assumptions about U.S. population trends, the future price of world oil, and national energy and economic growth projections, the U.S. Department of Energy's (DOE's) Office of Policy, Planning and Analysis has offered the following synthetic fuels forecast (Table 2). The coal consumption levels for 1985 are forecast at between 0 and 15 mmt/yr. The 1990 mid-range forecast by DOE (1981a) is considerably below the CONAES (1979) and ERDA (Energy Research and Development Administration) (1976) forecasts and, for a 335,000 bpd of oil equivalent production for liquids and high and low Btu gas, requires only 60 mmt/yr of coal. The number might be as low as 25 mmt/yr of coal and as high as 110 mmt/yr. By the year 2000, the mid-range forecast reaches 1.8 mmbpd of oil equivalent from coal, slightly favoring coal liquids over gas, and requires about 300 mmt/yr of coal. However, the production levels could be as low as 850,000 bpd of oil equivalent or as high as 2.6 mmbpd of oil equivalent, requiring something between 135 to 415 mmt/yr of coal. The DOE (1981a) high coal-based synthetic fuel forecast for the year 2000 coincides with the CONAES low case (Business as Usual) for the same period. Both are considerably lower than the earlier Energy Research and Development Administration forecast (1976).

TABLE 2. SYNTHETIC FUEL PRODUCTION*

Type	Mid-range (1990)	Range (1990)	Mid-Range (2000)	Range (2000)
Liquids				
Shale Oil	225	100-400	1100	600-1600
Coal Liquids	150	75-350	1100	550-1700
Biomass Liquids	100	50-150	200	100-300
Gases (Coal-Derived)				
High Btu	75	30-125	340	150-450
Low to Medium BTU	110	50-175	340	150-450
Total	660	305-1200	3080	1550-4500

*Figures shown are for equivalent of 1,000 bpd oil.
Source: DOE 1981a, Table 7-3, p. 7-8.

The DOE (1981b) forecast for total coal demand in the year 2000, which reaches 1.8 billion t/yr, has important implications for national energy policy and implementating local planning. Issues related to air quality, adequacy of transport and ocean-loading facilities, electric power growth, capital investment requirements and Federal coal lands leasing all need immediate attention. The last part of this chapter will examine some of these issues in the context of expected economic growth and development as well as environmental constraints.

Montana University Coal Demand Study (1976)

In the first attempt at a regional projection of coal demand from the NGP (1976) based upon spatial market definition and energy factors within that market, the Montana University Coal Demand Study (MUCDS) projected no coal-based synthetic fuel development before 1990 in Montana, Wyoming and North Dakota. In the decade 1990 to 2000, although synthetic fuel development seemed possible but not obvious, MUCDS decided not to forecast, arguing that the factors controlling coal-based synthetic fuel development 15 years in the future were not well known enough to warrant discussion.

The 1982 situation is not much different. Although world oil prices are higher than in 1976, the future price trend is still not undoubtedly known, even for a relatively short period of time. Water requirements for community social/economic activity, especially in the West, remains the single most important resource question in the decades ahead. Water rights ajudication; Indian water; interbasin transfer; instream flow requirements and ground-water quality, quantity and use have become issues that can severely limit the size and place of a coal-based or oil shale energy industry. The ownership of coal, the ability to raise capital for investment in expensive technology, the pricing of different forms of energy and the continuing impact of conservation and renewables all play important roles in the structure of the American energy industry. That structure can and does influence the downstream planning for our energy future and, based upon our ability to answer the questions raised, will determine the public and private commitments to the mixtures of energy sources for the 21st century.

Still, it is appropriate to assess the most probable level of coal-based synthetic fuel development in the Northern Great Plains to the year 2010. A few assumptions are necessary to set the baseline for this forecast. First, nothing will be on-line in the NGP (nor in the nation) prior to 1990. Normal construction lead times of ten years are necessary for plants as large and complex as standard, unit-size coal syngas or syncrude facilities, matching large coal or nuclear-fired power plants. The technology to be used will probably be first generation during the 1990s; therefore, a commercial coal-based synthetic fuels industry will not emerge in the United States until near the turn of the 21st century. The period 1985 to 1995 will be spent in constructing and operating a few well-chosen plants around the country to demonstrate a range of technologies, operating conditions and product slates. Environmental studies related to plant operation should have high priority for research and reducing the consumptive use of water will be an important operational goal. Lastly, both in terms of market demand and energy pricing, synthetic fuels from coal will not be securely competitive with other forms of energy until well beyond the year 2000.

In the Northern Great Plains, demonstration facilities will come on-line during the period 1990 to the year 2000. Each plant will probably be standard size, capable of producing about 25,000 to 50,000 bpd of oil equivalent fuel. It appears likely now that by 2000 A.D., there will be at most, only three or four plants producing 150 to 200 mbpd of oil equivalent and requiring between 15 and 20 mmt/yr of coal from the NGP. Two or three of these plants will be syngas producers and perhaps one will make a syncrude product. It is likely that North Dakota and Montana will have no more than one plant, and Wyoming could have one or perhaps two different facilities.

As these are mainly demonstration and learning facilities, the NGP will not be involved in seriously enhancing the fuel supply through synthetics until after the year 2000. The number of plants to be constructed will depend as much upon the social and other resource constraints of the region as it will on national demand. Construction will move slowly as the ability of the area to absorb very large scale, rapid construction schedules is non-existent. State involvement and oversight will be more obviously apparent than at present, as more and more of the social, health and welfare concerns of the people move to state and local levels of consideration. The ability to develop new towns and to expand old, small, agricultural communities will present a social barrier to rapid construction rates and high production goals.

It is unlikely that any one of the three NGP states will be able to maintain more than two construction schedules simultaneously, allowing about five years for a plant to be completed. This rate of construction could add 12 new synfuel plants at the most in the NGP by the year 2010, requiring an additional 60 mmt/yr of coal, or 75 to 80 mmt/yr total. A low projection, half the level above (six new synfuel plants), would require an additional 30 mmt/yr of coal by the year 2010, for a total of 45 to 50 mmt/yr of coal. These estimates are conservative given the forecasts reviewed above; however, they better accommodate the realities of building and operating large, complex, expensive and resource-demanding energy facilities in the NGP. The forecast also implicitly includes the attitude people in the region have toward potentially disrupting energy development on their home ground. This attitude may change dramatically over the next twenty or thirty years, but the limits to accommodating energy growth in the NGP are recognized by all parties concerned and will set a natural cap even if an economic limit is not in sight. Table 3 summarizes the forecast for coal-based synfuels in the Northern Great Plains.

In this discussion the level of coal export from the NGP to support a national or international synthetic fuels industry was not considered. On a national basis, one estimate might be to allocate a share of the coal supply to the NGP, assuming that by the year 2000, exports to water, capital and human resource centers will take place. The level of national synfuel development can be taken as the mid-range of the 1981 (DOE 1981a) forecast. The NGP share of the national market is arbitrarily set at the same value as the (NGP) share of the total national coal market. In this case, that share is 15% of domestic consumption in 1980 and is estimated to grow to between 25% and 30% in the years 1990 to 2000. With a mid-range domestic market in 1990 of about 1.1 billion tons of coal (according to DOE), the NGP could supply from 250 to 275 mmt of coal nationally.

The coal-based synthetic fuel demand nationally in 1990 has an estimated 60 mmt mid-range value (DOE 1981a). It is unlikely that the NGP will supply any of the converting facilities outside the NGP region in this time frame. Within the region, coal conversion to synthetic fuels is not expected to take place before 1990. As stated above, the national DOE (1981a) forecast for synthetic fuel production from coal by 1990 seems unlikely, and coal demand for this purpose could be as low as 20 to 30 mmt.

By the year 2000, national consumption of coal is estimated at approximately 1.6 billion tons, with synfuels accounting for 285 mmt at the DOE (1981a) mid-case forecast. The NGP region might consume 15 to 20 mmt of this locally and capture a 30% share of the remaining market, which would amount to an additional 80 mmt/yr of coal and brings the synfuel coal demand for the NGP in the year 2000 to 100 mmt.

By the year 2010, the NGP could have 15 plants consuming an estimated 80 mmt/yr of coal in conversion to coal-based synfuels. The NGP share of the national coal market could, under this scenario, rise to between 35% and 40% of the total, especially as lower operating costs and more concern for air

TABLE 3. COAL-BASED SYNTHETIC FUELS IN THE NORTHERN GREAT PLAINS

Scenario	1990	2000	2010
High Growth			
1000 bpd oil equivalent	0	200	800
Mmt/yr coal		20	80
Low Growth			
1000 bpd oil equivalent	0	150	450
Mmt/yr coal	0	15	45

quality control, due to the heavy reliance on hydrocarbon fuels, continues to place more pressure on Western coal production.

Nationally, coal demand for the synfuel market will be considerably below the low growth forecast by CONAES in 1979. For the year 2000, the CONAES low growth (Business as Usual) is at the top of the range (high growth) for the DOE (1981a) forecast. The mid-range DOE (1981a) forecast for the year 2000 is 65% of the CONAES low forecast. Using the same ratios, a plausible forecast for the year 2010 might require 500 mmt of coal nationally for synfuels. With as much as 80 mmt allocated for conversion in the NGP, and the (NGP) region exporting 40% of the nationally required remainder (170 mmt), the total production for coal synfuels in 2010 in the NGP could reach 250 mmt/yr. It appears unlikely that coal-based synfuel growth will be much faster than the forecast above; on the other hand, depending upon supply, availability, and price, the growth could be much slower.

The preceding discussion presupposes that the DOE mid-range forecast is reasonable. It seems more likely that NGP export for synfuels will not exceed consumption in the region, which would imply export in the year 2000 of 5 to 20 mmt/yr and 45 to 80 mmt/yr in 2010. Therefore, the total coal demand for synfuel from the NGP would only reach 30 to 40 mmt/yr in 2000 and 90 to 160 mmt/yr in the year 2010. These estimates (Table 4) are speculative at this time.

TABLE 4. COAL FORECAST FOR NGP SYNTHETIC FUELS*

	Year	
	2000	2010
Northern Great Plains Coal		
High Growth		
Region	20	80
Export	20	80
Total	40	160
Total Growth		
Region	15	45
Export	15	45
Total	30	90

*Figures in mmt/yr of coal.
Source: Silverman *et al*. 1982, p. 16.

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DEMAND FOR NORTHERN GREAT PLAINS COAL TO THE YEAR 2010

by

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LIST OF ACRONYMS

CONAES--Committee on Nuclear and Alternative Energy Systems
DOE--Department of Energy
EIA--Energy Information Administration
ERDA--Energy Research Development Administration
ETSI--Energy Transportation Systems, Inc.
FERC--Federal Energy Regulatory Commission
FGD--Flue Gas Desulfurization
ICC--Interstate Commerce Commission
MUCDS--Montana University Coal Demand Study
NCS--National Coal Association
NERC--National Electric Reliability Council
NGP--Northern Great Plains
ORNL--Oak Ridge National Laboratory
PSD--Prevention of Significant Deterioration
RNSPS--Revised New Source Performance Standards
SERI--Solar Energy Research Institute
SIPs--State Implementation Plans
SLED--State Level Electric Demand (Model)

INTRODUCTION

The Northern Great Plains (NGP), and in particular the Powder River Basin centered around Colstrip and Decker, Montana, and Gillette, Wyoming, is rapidly becoming the major coal-producing region in the United States. The other NGP coals of importance are the lignites of the Fort Union Basin of eastern Montana and North Dakota (Fig. 1). NGP production has jumped from approximately 15 mmt as late as 1976 to 96 mmt/yr in 1979. Firm utility contracts provide a floor on likely production in 1985 of 182 mmt/yr. Because of low sulfur content, the low production costs associated with unusually thick and strippable coal seams, and the ease of assembling large reserve blocks, this region has accounted for approximately 50% of the incremental coal production in the U.S. in the 1980s. Long-term significant production levels are likely to continue, as the NGP states of Montana and Wyoming alone contain 40% of the total identified U.S. coal reserve base.

The future levels of coal production from the NGP area will be closely tied to real increases in mining labor and rail transportation costs and the growth rate in electrical consumption. The other key factors determining future production levels will be Federal policy for sulfur dioxide air pollution, transportation regulation, fuel switching, and Federal subsidy and regulation of nuclear and synthetic fuel plants. The public interest in this area is compounded by the fact that the Powder River Basin contains the largest pool of undeveloped leased Federal coal in the United States and already accounts for about half of all Federal land coal production. The scale, timing, and location of future coal development in the West is therefore closely tied to Federal reclamation and leasing policy.

In a recent study by Silverman et. al. (1982), an attempt was made to identify most of the key economic and policy linkages that will determine the future level of NGP coal production. The basic model used was the economic model of spatial markets. This is a different strategy than the linear programming approach commonly taken in the large national coal models, because the national models have been unable to produce accurate, regionally disaggregated forecasting results. Another aspect of this failure is the tendency of the linear programming models to lack robustness in the face of parameter changes. The results reported in this paper indicate a level of future coal production for the NGP that is considerably lower than what has been predicted by the DOE/ICF national coal model. Based on contract information presently available, the results reported here appear to be more consistent with reality.

The extent to which NGP coal will be developed in the future depends in a large part on the demand for electricity in its market area. Almost all of the Fort Union Basin utility coal was burned mine-mouth, while only 12.6% of the 1979 Powder River Basin utility coal was burned mine-mouth; the rest was exported by railroad to a 15-state market area. The 1976 Montana University Coal Demand Study (MUCDS) did a simple analysis of the Midwest market area for NGP coal and found that the demand was sensitive to sulfur dioxide air pollution control policies (MUCDS, 1976). Since 1976, substantial changes have occurred in the parameters which define the market area for NGP coal. New air quality regulations stemming from the 1977 amendments to the Clean Air

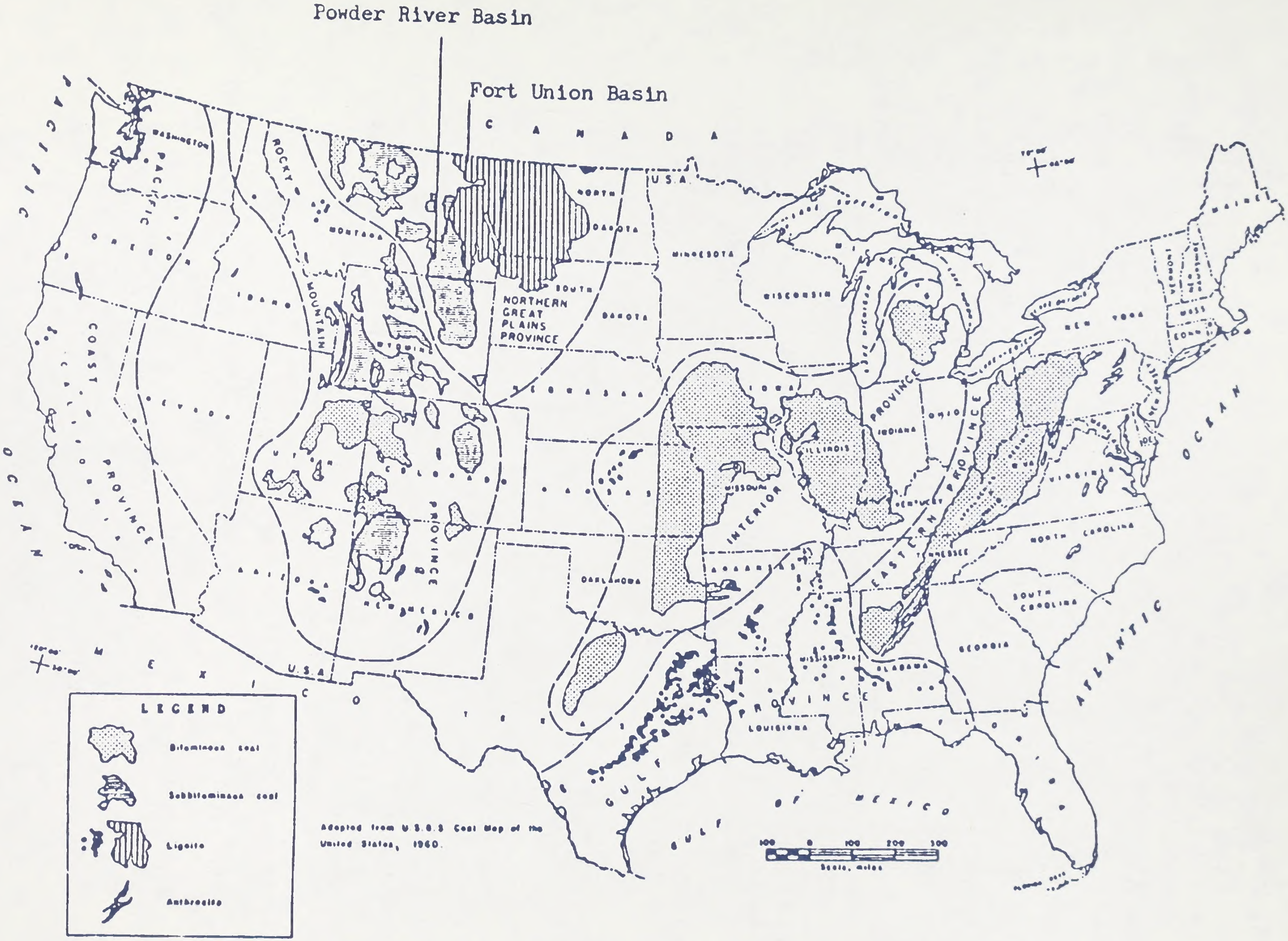


Figure 1. Bituminous and subbituminous coal and lignite fields of the coterminous United States (U.S. Bureau of Mines 1976).

Act are coming into effect just as Congress begins a major review of the Clean Air Act and a new administration takes office. Substantial increases in unit train coal transportation costs have caused utilities to reevaluate their commitments to long distance railroad coal hauling. Coal slurry pipelines and high voltage transmission lines are viable alternatives to rail transportation, but they face considerable public opposition. Mine-mouth coal prices are increasing in real terms because of increasing mining costs, higher prices for substitute fuels, environmental controls, and stagnation in productivity.

Our analysis of the future production of NGP coal is based on a four-step methodology similar to that used by MUCDS in 1976. The first step is to define the spatial market in which NGP coal is cost-competitive. Secondly, a forecast is made of the growth rate in electrical consumption within this market area. Thirdly, the share of increased electrical consumption that will be met by base load coal generation is determined (interfuel substitution); and fourthly, the NGP share of the total coal consumed in the large market area is determined (intrafuel substitution).

DEFINING A SPATIAL MARKET FOR NGP COAL

Spatial Model

Commodities which have a low value to weight ratio, such as coal or cement, have a fairly well-defined geographical market. The key to the spatial market idea is that the market boundary between two competing supply centers (such as Gillette, Wyoming, and Centralia, Illinois) is where the sums of transportation and mine-mouth costs and other coal-related expenses are equal. For power plants on one side or the other of the boundary, the cost advantage lies with one or the other of the producers due to lowered transportation costs. The locus of equal cost points defining the market boundary is often a hyperbolic curve.

We have assumed that utilities will choose the cost-minimizing coal and that relevant costs include the free on board mine price, regional coal transportation rates, power plant costs (which will vary with the heat content of the coal), pollution control costs (in part a function of sulfur content), and expected escalation rates for each of these factors. These are the coal-specific factors analyzed as a function of policy and market conditions. The question of where plants will or should locate has not been addressed; this is a function of site-specific factors such as water availability, proximity to load centers, transmission grids and rail lines, and local air quality regulations. Rather, the question "Given the site, what coal will be used?" is being analyzed. While rail rates have been devised that are specific to coal supply centers, the simplifying assumption has been made that all coal transportation is by unit trains.

A major extension of the current model beyond the 1976 MUCDS is to define a completely bounded market region based on seven competing supply centers (as opposed to one, Illinois, in 1976). In addition, a methodology has been developed to forecast the population-weighted fraction of a given state that lies within the NGP market area. This closer specification was motivated by the fact that the forecast market boundary bisects many of the major energy-consuming states in the South Central and Midwestern United States.

Since what share of load centers lie within the NGP market is essentially a prediction, an implicit assumption is that the cost of transporting coal by wire or rail is approximately equal. Based on incremental costs, this assumption appears to be approximately correct. Another major assumption of the model is that the relevant distances from a given coal supply region can be approximated by the distance from a single point source (i.e., Gillette, Wyoming, for the Powder River Basin). Perhaps this may not be functionally correct for load centers close to the relatively large East Interior Basin. It is also assumed that the coal in a given region is sufficiently homogeneous that it can be characterized by the average qualities (Btu content, sulfur, free on board price) used in the model.

Transportation

Energy shipments out of the Northern Great Plains are mainly by rail. The only other important, current mode is by high voltage electric transmission lines. As noted, conversion in minemouth plants and shipment of energy by wire is associated with 97% of North Dakota lignite, but only 12% of Powder River coal, which reflects the economics of rail transport for low Btu lignite. As developed below, the market for NGP coal is very sensitive to available transportation modes and costs. A wide range of future costs are possible, dependent on Interstate Commerce Commission (ICC) railroad policies, real escalating cost factors (labor, materials, fuels), system capacity limitations, and the importance of new technologies, particularly coal slurry pipelines.

The dominant fact in the current NGP transportation picture is that, since 1965, coal freight rates have been increasing very rapidly at just under 4% per year, which implies a doubling of the real cost of rail transportation in 18 years. Continuing increases will partly be due to recent legislation aimed at deregulation of the railroad industry (Railroad Revitalization and Regulatory Reform Act of 1976 and the Staggers Rail Act of 1980). Utilities in Texas receiving shipments of Wyoming coal through Burlington Northern have sued the ICC about rate increases allowed by these new Federal policies. The House Subcommittee on Oversight and Investigations has gone on record as concluding that the recent cost increases allowed by ICC are unjustified. The implication of these issues for long-term rail rates will depend on how deregulation is tempered by policy toward captive traffic and actual competition from other carriers. Regulatory policy and competition will probably be much more important than the concern that surfaced during the Carter administration over rail capacity as a constraint on coal production.

Capacity concerns do not appear justified since railroads can expand rail facilities faster than mines and power plants can come on line. Fairly smooth continuous expansion of rail facilities is possible through incremental siding additions and sophisticated traffic and signal control. Alternatively, variable cost increases through rerouting can be incurred as a substitute for capital investment. The marginal cost function for increased capacity by rerouting out of the NGP is quite elastic, on the order of a 5% increase over a range of 50 to 300 mmt/yr. Previously predicted shortfalls in railroad capacity in the West by 1990 are very unlikely to happen, partly because these shortfalls were predicated on production levels that were unrealistically high but also because of actual capacity expansion and rerouting flexibility.

To a certain extent, the structure and level of rates of unit trains in the West are ongoing experiments. Recent rapid increases in these rates have led to complaints that rates were initially set at low "promotional" levels; whether this is true or not, carriers have experienced greater track damage and slower turnaround time from heavy coal traffic than has been anticipated.

Probably a more important consideration than capacity for future rail rates is competition from other carriers. For NGP coal, the most important alternatives are coal slurry pipelines. Three pipelines originating in Gillette, Wyoming, have been proposed with destinations to White Bluffs, Arkansas; Houston, Texas; and the state of Washington. Presently only one coal slurry pipeline is in operation in the U.S.--the 273-mile Black Mesa pipeline built in 1970 in Arizona and Nevada. Developing coal slurry pipelines for western coal hinges on policy regarding rights of eminent domain and the acquisition of water rights. Repeated efforts to pass Federal eminent domain legislation for slurry pipelines have failed; however, mixed success has been achieved on a case-by-case basis at the State level. A 25-mmt/yr pipeline needs approximately 1500 ac-ft of water. Therefore, it is more of a political than an economic or resource problem when considering a relatively small number of slurry pipeline projects.

In part because of the absence of operating experience for coal slurry lines of the length now being proposed (1100 to 1400 mi for the NGP lines), cost estimates in 1979 dollars vary from 5.3 to 9.9 mills per ton-mile, on the same order as unit train costs in 1979.

As noted, the other major means of transporting NGP coal is by wire. The relative economics of coal by wire versus coal by rail depends on site-specific factors. Unlike rail, there appear to be major environmental and political constraints to additional transmission capacity. Five comparative cost studies indicate that there is no unambiguous cost advantage to any of the competing modes (wire, rail, and slurry pipeline). The result is that (1) case-specific studies are required, (2) environmental impacts may be the dominant consideration, and (3) market structure considerations, in light of comparable economics, may be paramount. The latter would imply that, other things being equal and given the dilemma of railroad regulation versus monopoly, policy perhaps should favor a diversity of transportation modes. Case study findings indicate that a Wyoming to Washington state slurry is not competitive for any plausible range of conditions, but that the proposed Energy Transportation Systems, Inc. (ETSI) pipeline to White Bluff, Arkansas, and the Wytex line to Houston, Texas, are competitive.

In summary, the main conclusion of the transportation analysis is that rail will likely continue to dominate NGP energy transportation. In addition, there may also be increased competition in the NGP area from other railroads. Currently, NGP shipments are almost entirely by Burlington Northern; however, the Chicago and Northwestern may soon gain access to Campbell and Converse County mines in Wyoming.

Moreover, the future of large-scale minemouth generation with coal export by wire is likely to be limited, at least on the Montana side of the Powder River Basin. Coal-rich areas are resisting becoming boilerrooms and transmission corridors for the rest of the country. Especially for markets in Washington and Oregon, the environmental capacity of the finite number of mountain passes and river valleys throughout the Northern Rockies may already have been reached.

To the extent that rail rates continue to escalate as in the past, it is very doubtful that new coal contracts will be forthcoming from the midwestern and south-central portion of the current market. South-central utilities that contracted for Powder River coal in the early 1970s are now finding that due to increased rail rates, local lignite and even foreign coal shipped in through the Gulf of Mexico may be more cost-effective. A very sizeable portion of potential future NGP coal exports to Texas, Louisiana, and Arkansas may well hinge on proposed coal slurry pipelines.

Coal Contracts

NGP coal deliveries in 1979 were made to utilities in 18 states: Arkansas, Colorado, Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Texas, Wisconsin, and Wyoming (Table 1). In addition, 1980 contracts included coal shipments to Louisiana and Oregon. The proximate states of Idaho, Washington, and Oregon also receive "coal by wire" via ownership in minemouth NGP plants. Of these 22 states, only the Ohio contract is of a short-term nature and unlikely to be renewed. Accordingly, the market area analysis discussed below has been largely restricted to a 21-state area.

The total 1979 consumption of NGP coal by utilities was 87 mmt, with 85% from the Powder River Basin and 15% Fort Union lignite. Seventy-five percent of the coal was exported out of the NGP states of Montana, Wyoming, and the Dakotas; 25% is used in minemouth generation.

After correcting for "coal by wire" within the 21-state region, NGP currently supplies 31% of all utility steam coal. The other seven major supply centers are the Eastern Interior Basin (Illinois), Texas (lignite), Washington (Centralia), Utah (Uinta Basin), New Mexico (San Juan Basin), Colorado, and southern Wyoming (Green River/Hams Fork Region). NGP coal has generally lower Btu content (8,800 Btu/lb average versus 11,000 to 12,000 Btu/lb for Interior and Utah coals), lower sulfur content (0.6% for most western coals versus 3% for most Illinois coal), and can be produced at a lower cost ($8-$12/ton versus approximately $20/ton free on board for most of the other coals).

Price increases for all coals are forecast based on factor cost shares and relative expected real increases in labor and capital costs. Price increases in underground coal are closely related to labor costs, since the coal factor cost share for underground mining is approximately 60% as opposed to 25% for surface mining. As noted above, the market size is sensitive to this factor as (other things being equal), higher wages improve the relative advantage of surface-mined NGP coal. A major simplification in the analysis is that reserve depletion will not be a major cause of price rise in the foreseeable future. This assumption of relatively elastic supply appears justified given the reserve base relative to the forecast period and the lower forecasted growth rates for electricity.

Given the 5- to 10-year lead time in establishing a mine, firm contracts are the best basis for forecasting coal production in 1985 and 1990. Utilizing a

TABLE 1. ORIGIN AND DESTINATION OF NGP COAL--1979 ELECTRIC UTILITY DELIVERIES[a]

	Origin					
	Powder River		Fort Union			Percent[b]
Destination	MT	WY	MT & SD	SD	Total	of NGP
Arkansas	-	1,557	-	-	1,557	1.8
Colorado	-	2,734	-	-	2,734	3.1
Illinois	4,107	2,570	-	-	6,677	7.7
Indiana	813	610	-	-	1,423	1.6
Iowa	180	5,631	-	-	5,811	6.7
Kansas	6	5,087	-	-	5,093	5.9
Michigan	3,727	-	-	-	3,727	4.3
Minnesota	11,451	-	-	699	12,150	14.0
Missouri	-	962	-	-	962	1.1
Montana[c]	3,207	-	304 (MT)	-	3,511	4.0
Nebraska	-	2,088	-	-	2,088	2.4
North Dakota[c]	3	-	168 (SD)	9,430	9,601	11.0
Ohio	-	3,648	-	-	3,648	4.2
Oklahoma	-	4,368	-	-	4,368	5.0
South Dakota[c]	-	260	-	2,477	2,737	3.1
Texas	1,609	8,640	-	-	10,249	11.8
Wisconsin	2,719	2,016	-	-	4,735	5.4
Wyoming[c]	-	5,861	-	-	5,861	6.7
Subtotals						
NGP states	3,210	6,121	472	11,907	21,710	25.0
Non-NGP states	24,612	39,911	-	699	65,222	75.0
Totals	27,822	46,032	472	12,606	86,932	100.0

Source: Silverman et al. 1982, p. 7-9.

[a] Figures in 1,000 tons.

[b] Percent by weight; may not equal 100 due to independent rounding.

[c] NGP coal-producing state.

number of sources, firm contracts were identified for NGP coal for 181.8 mmt/yr in 1985 and 195.2 mmt/yr in 1990. The 1990 estimate would be adjusted upward, to 213 mmt/yr, taking into account the proposed power plants presently not contracted. This is considerably lower than a recent estimate by the Office of Technology Assessment (OTA 1981c; adjusted to include Fort Union coal) of 258 mmt for 1990. Contracts have been identified in the OTA estimate which are now cancelled; therefore, 258 mmt/yr is expected to be the high side forecast. Appendixes A and B contain complete plant and contract information (contact author or BLM if you want copies of this information).

Spatial Market Results

To standardize the analysis (Silverman, et. al; 1982), the utility coal choice was modeled assuming a 500 Mw boiler, which is close to the actual average of 511 Mw for boilers on order for the 1980-1995 period. We chose a 65% lifetime capacity factor and used a real fixed charge rate without tax preference of 9.33% and 7.4% with tax preference. All annual costs subject to real escalation (over and above inflation) were leveled at the real weighted cost of capital of 3.77% for the utility industry. The capital costs of new capacity varied substantially by region and with the Btu content of the coal. For example, subbituminous-fueled capital costs average $70/kWh more than bituminous, and lignite is $58/kWh more than subbituminous (1980 dollars). We also used coal-specific heat rates (Btu/kWh) in calculating operating costs.

The flue gas desulfurization (FGD) costs for NGP coal were significantly increased by the 1979 Revised New Source Performance Standards (RNSPS). The 1971 NSPS of 1.2 lb of sulfur dioxide per million Btu could be met by some NGP coal without scrubbing. Under the RNSPS, most NGP coals now require 70% scrubbing. As an example, NGP coal relative to Illinois coal has a $90/kWh advantage in FGD capital cost but requires an offsetting $73/kWh in plant capital cost due to lower Btu content. The major cost advantage to NGP coal vis-a-vis Illinois coal is now largely in free on board price ($8.80 versus $21.00 per ton or $0.55 versus $0.93 per million Btu for the base case).

FGD costs were defined for four air pollution control policy scenarios. The state air pollution control policy review showed that most western states are requiring 90% scrubbing even on low-sulfur coals for Prevention of Significant Deterioration (PSD) and visibility concerns. Accordingly, the base case for FGD costs was 90% SO_2 removal for Western States and RNSPS elsewhere. The high case was 90% SO_2 removal everywhere (including low-sulfur coals burned in the Midwest). A 0.8-lb. $SO_2/10^6$ Btu emission ceiling which is one of many possible revisions of the current policy, was also examined.

Transportation costs were based on a region-specific regression analysis of unit train tariffs; the variable cost component averaged 11.3 mills per ton-mile. Aside from the RNSPS in 1979, the major change in coal economics since the MUCDS study in 1976 has been the unanticipated and very large annual real increase in coal mining wage rates and transportation charges. A careful analysis of historical real increases for these and other parameters, using selected price indexes available for the period 1965 to 1980, was characterized by lower pre-embargo (pre-1973) than post-embargo rates. A regression estimate of the price index over the entire period was prepared for a base case for 1980, 1990, and 2000. A 95% confidence interval on the year

2000 A.D. point estimate allowed a derivation of a "low" and "high" annual growth rate for the intervening years.

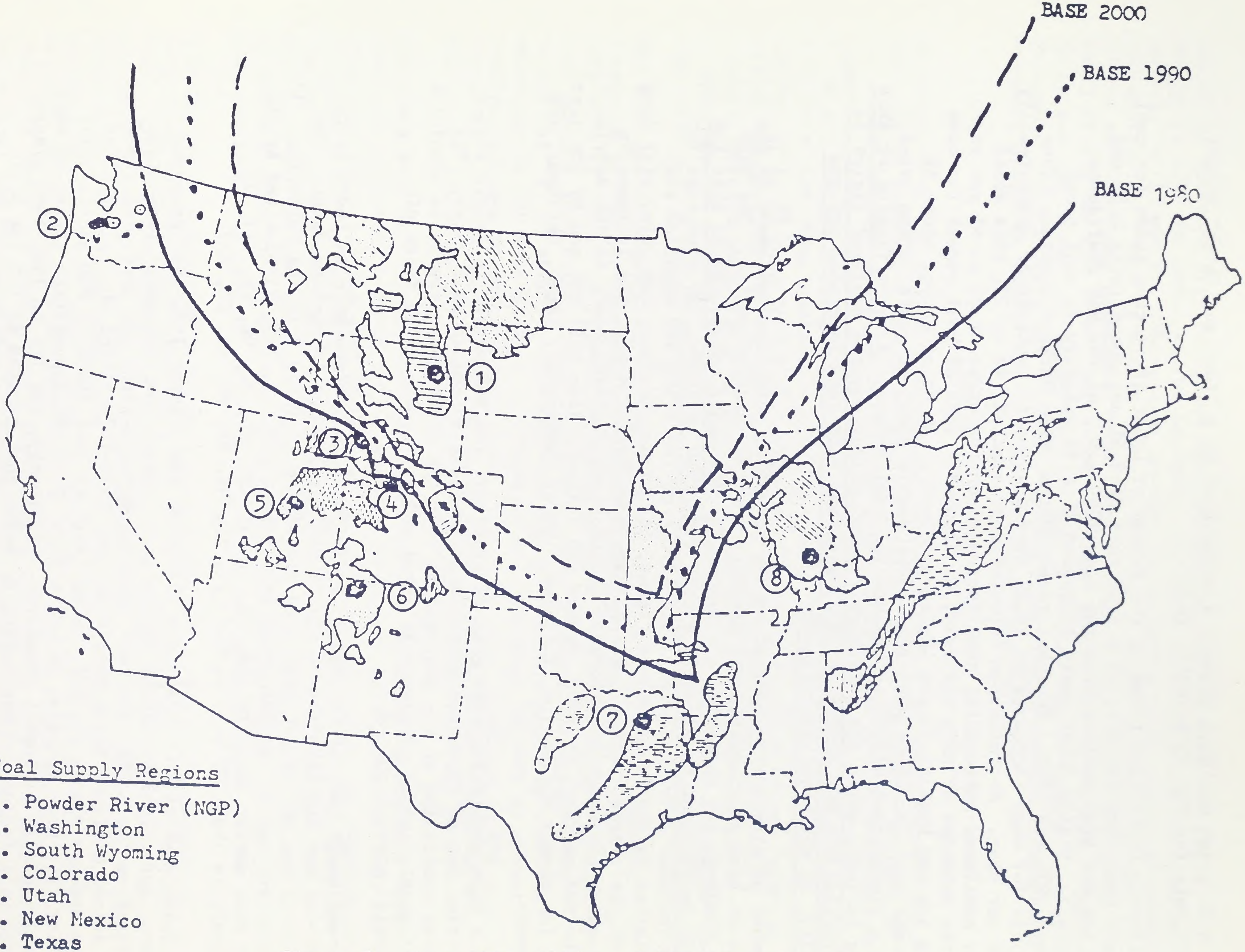
The 15-year historical trend on the Bureau of Labor Statistics index for coal freight rose very steeply, at a real rate of 3.5% per annum (with 2.8% and 4.3% low and high derived from the year 2000 A.D., at the 95% confidence interval). Mining labor costs increased at 4.2% annually in real terms between 1971 and 1980. The most recent United Mine Workers contract (June 1981) is for wage increases of 38.5% over a 40-month contract or approximately 10.3% per year. At inflation rates of approximately 4% to 7%, this would imply continued substantial real increases on the order of 2% to 6% per year. For the purposes of this analysis, we assumed a base 2% real annual increase and a low and high of 0% and 4%, respectively. As noted above, since 4% compound real increases mean real costs double every 18 years, these rates have a significant effect on the spatial coal market. A major finding of this study is that, while air pollution control policy was the dominant factor in determining the NGP market in 1976, wage and rail rate increases are now equally, if not more, significant.

A number of alternative spatial market scenarios were examined based on the range of base year costs, real escalation rates, and FGD policy. The base case findings are summarized in Figure 2. The major conclusion is that the market is forecast to steadily shrink from 1980 to 2000. The base case for 1980 includes only 18 states. The effect of the RNSPS and expected real escalation is that four states (Texas, Louisiana, Indiana, and Ohio) will drop out of the current market. In the base case market areas, the increase in rail rates dominates the increase in underground mining costs to the detriment of the NGP market. By 1990, Oregon and Illinois also fall out and by the year 2000 the market shrinks to 12 states, losing Washington, Idaho, Oklahoma, and Arkansas.

When a high escalation rate case is examined, the NGP market is fairly stable over time due to increased labor costs matching increased rail rates. The general conclusion of the analysis is that the market boundary is as sensitive to plausible levels of change in labor and rail costs as it is to air pollution control policy.

An unambiguous test of the model is difficult to perform because there is no clear-cut age distribution of plants due to slippage in on-line dates. The states of the NGP market have been classified in Table 2 by the following: 1) if they are out of the 1980 base area market (IN, LA, TX), 2) bisected by the 1980 base market boundary (AR, CO, ID, IL, MI, MO, OK, OR, WA, WY), or entirely in the 1980 base market (IA, KS, MN, MT, NE, ND, SD, WI).

The plant generation classes are 1976-1980 new plants, 1981-1990 proposed plants, and 1976-1990 strict SO_2 control. Since the 1980 model prediction is based on the RNSPS, the best correspondence between the predicted share and the actual contract share should be the "1976-1990 strict SO_2" plant class. These are new plants actually being built to meet RNSPS or PSD plants built earlier that were required by state SIPs (State Implementation Plans) to meet roughly equally stringent standards. Similarly, the fit to 1981-1990 plants (which will include plants coming in under the old NSPS of 1.2 lbs $SO_2/10^6$ Btu) should be worse, yet better than the fit to 1976-1980 plants. The



Coal Supply Regions

1. Powder River (NGP)
2. Washington
3. South Wyoming
4. Colorado
5. Utah
6. New Mexico
7. Texas
8. Midwest

Figure 2. Base 1980, 1990, and 200 NGP market areas.

TABLE 2. COMPARISON OF NGP MARKET AREA SHARES: CONTRACTS VS. FORECAST (PERCENT OF UTILITY COAL)

	Coal Contract Shares			Market Model Population Shares*	
State	New Plants (1976-1980)	Proposed Plants (1981-1990)	Strict SO_2 Control	1980 Base	Range (Low-High)
States Outside 1980 Base NGP Market Area					
IN	0	0	0	0	0 - 17
LA	0	61	0	0	0 - 0
TX	62	22	0	0	0 - 0
Subtotal	45	25	0	0	---
States Bisected by 1980 Base NGP Market Area					
AR	100	75	0	35	35 - 85
CO	22	75	36	81	12 - 95
ID	14	100	28	100	16 - 100
IL	0	0	0	5	2 - 87
MI	26	85	0	0	0 - 36
MO	26	37	42	40	37 - 40
OK	100	100	100	45	45 - 45
OR	61	100	75	8	8 - 100
WA	71	100	90	10	10 - 97
WY	79	100	92	81	81 - 100
Subtotal	51	73	59	34	---
States Totally in 1980 Market Area					
IA	100	67	0	100	100 - 100
KS	100	100	100	100	100 - 100
MN	100	100	100	100	100 - 100
MT	90	100	100	100	100 - 100
NE	100	100	0	100	100 - 100
ND	100	100	100	100	100 - 100
SD	0	0	0	100	100 - 100
WI	100	100	100	96	90 - 100
Subtotal	100	93	95	100	---
Subtotal for States Bisected or in 1980 Base Market Area	70	81	75	-	---
Total for All States in the Current 1979-1980 Market Area	61	56	51	-	---

* From Table 16, Chapter 8, Silverman et al. 1982.

results are roughly consistent with this hypothesis. The contract share for plants predicted to be outside the market drops to zero with the RNSPS plants. Similarly, NGP gets 95% to 100% of the local share for states predicted to be entirely within the market. The fit is less convincing for the bisected states. A problem with the data fit is that the PSD plants may not have expected high rail increases.

It appears that the model is predicting the overall utility coal choices fairly consistently. However, there is a sizeable area in the Midwest which is apparently sensitive to modeling assumptions.

FORECASTING ELECTRICAL CONSUMPTION IN THE NGP MARKET AREA

Electrical Demand

As noted, Northern Great Plains coal is largely used as an input in producing electric energy. Accordingly, forecasting the derived demand for coal requires forecasting the demand for the final product: electricity.

The prominent electric forecasting methodologies--trending, macroeconometric, and econometric/end-use--have been reviewed and analyzed by a number of authors; examples of the two latter types of models include Baughman et al. (1979) and the Oak Ridge National Laboratory (ORNL) State Level Electric Demand Model (SLED), (Macroeconometric); and Oregon Department of Energy's residential end-use model (Corrigan et al., 1981) and the ORNL commercial end-use model (Jackson et al., 1978). One might conclude that only the end-use models provide the flexibility to analyze end-use specific policy measures, such as appliance or building performance standards. However, the cost of this feature is greatly increased data requirements and computational complexity. Because of the lack of data, currently specified models require substantial judgment on the part of the forecaster/model builder.

Silverman et. al. (1982) reviewed existing electrical consumption forecasts for the 21-state NGP market area: the Energy Information Administration (EIA) model, the SLED model, and the National Electric Reliability Council (NERC) forecast. A major effort was undertaken to use the "off-the-shelf" SLED model in their study by updating base years and supplying exogenous inputs. Depending on price/income scenarios, SLED forecasts an annual average growth rate for electric energy of 2.8% to 4.06% with a base case of 3.44%. The EIA model of the Department of Energy incorporates a variable elasticity structure, and price and cross-price elasticities are generally larger (in absolute terms) than the SLED parameters. The EIA forecast also differs by incorporating the effect of some Federal conservation policies through end-use modeling. Nonetheless, the two models forecast very similar base case growth rates ranging from 2.7% to 3.5% to the year 2000 for the various scenarios.

By contrast the NERC forecast is a summary of individual utility forecasts. Until perhaps very recently, the dominant approach by utilities has been to use simple trending models. In the current period of declining growth, this has led to consistent overforecasting (for example, the NERC aggregate forecast for 1980 electrical consumption in the NGP market area, made in 1976, turned out to be high by 14%). The current NERC forecast for the market region is for 3.8% annual growth to 1990. This can probably be taken as an upper limit.

Most simple trending models are specified with electrical consumption as either a linear or log-linear function of time. The latter, of course, results in predicted constant compound growth rates, which can be misleading if there is a fundamental change in underlying demand. A Mann-Whitney nonparametric statistical test indicated that the most "significant" partitioning of the electrical consumption growth for the 1940 to 1979 period occurs in 1969; in other words, after 1969, growth rates were significantly lower. A visual inspection of actual growth in the market area suggested a logistic pattern instead of a constant growth model. This pattern is supported on theoretical grounds by appliance saturation and rising prices. Fitting an aggregate logistic curve to the 1940 to 1979 consumption for the 21-state area resulted in an excellent fit (R^2 of 0.998). The predicted growth rate for 1979 to 1990 was 3.5% and for 1990 to 2000, 1.34%. The confidence one can place in such a model is open to discussion. However, such a discussion should also recognize the relative statistical and empirical confidence that can be placed in macroeconometric and end-use models, given the standard errors of the fitted equations and the judgment involved in both parameters and inputs.

Conservation and Renewable Impacts on Demand

Possibly the major limitation of the forecasts discussed above is their failure to incorporate the impact of policy-mandated conservation and the substitution of renewables. Only the EIA forecast considers Federal conservation policy, and these effects, limited to existing policies, are unfortunately buried in the final numbers. All of the forecasts overlook the potentially significant effect of utility and state policies. What is needed is a scenario that explores the future in terms of a forecasting world view: events and time will grind on inexorably; the problem is to understand and predict the pattern.

Probably the most comprehensive recent statement of a "scenario view" is the Solar Energy Research Institute's (SERI) Report on Building a Sustainable Future. Without documenting methodology, SERI forecasts a "business as usual" growth in electrical consumption of 2% to the year 2000, at the lower range of most other forecasts. SERI then estimates that the likely growth rate would be reduced to 0.2% per year under a policy scenario that would realize all "cost effective conservation and on-site solar investments." Addition of all cost-effective on-site industrial cogeneration, wind, and photovoltaic systems could lead to a 1978 to 2000 annual average growth rate of electrical demand of -14% to 0.0%. If correct, these findings indicate that the consumption of NGP coal could be more heavily affected by energy policy for renewables and conservation than any of the conventional coal-related policy issues: SO_2 pollution standards, reclamation, leasing, transportation, coal taxes, mandated fuel-switching, and nuclear regulation and subsidies. Even for the near term, this is far from being a moot point, despite the current Federal administration's reduction of funding for conservation and renewables and its apparent disinterest in conservation policy initiatives.

Nonfederal (state and utility) conservation programs can have a potentially significant impact on energy demand. A microeconomic analysis (Silverman et al. 1982) of ceiling insulation levels (against leveled electric rates) in 13 of the NGP market area cities indicates optimal ceiling insulation averaging 7 to 12 inches. This contrasts with the existing ceiling insulation levels averaging less than 6 inches (based on DOE surveys). These specific findings are consistent with the conservation potential identified by SERI. States are apparently aware of and are beginning to exploit low-cost energy sources; within the NGP market area 16 of 21 states provided renewable energy tax incentives of some sort. The countries most aggressive policies in California are probably a major determinant of the relative low (1.4% annual average growth rate to the year 2000) increases in electrical consumption forecast by the California Energy Commission. The supportable conclusion is that state and utility energy conservation policies could clearly heavily affect the demand for coal.

While not discussed in this paper, the Pacific Northwest Regional Power Planning and Conservation Act has mandated a major ongoing evaluation of the regional potential for renewables and conservation to substitute for thermal facilities. This act and its implementation should provide a very interesting case study and shed considerable light on the conservation policy/resource and acquisition/load forecasting issues.

This is a considerable narrowing of the range considered plausible as recently as the 1976 MUCD study. Recognition of the potentially very significant impacts of state, utility, and Federal energy conservation policies over the long term might lead one to have greater confidence in the low end of the range, or even growth rates tending toward zero.

INTERFUEL SUBSTITUTION BY ELECTRIC UTILITIES: NUCLEAR, COAL, OIL AND GAS

Having identified the spatial market within which NGP coal is least cost, the problem remains of determining coal's share against the other competing energy sources: oil, gas, nuclear power, and hydroelectricity. One approach is to construct an econometric model that indicates the lagged response of fuel shares to relative price; however, the primary competitor against baseload coal generation in most of the market area is nuclear. The sharp discontinuities in historical nuclear commitments (discussed below) indicate that the nuclear future is likely to be markedly different than the past. This feature, together with the uncertainty surrounding nuclear costs, and the relatively long lead times for nuclear construction, suggests that it's more important to identify specific existing nuclear commitment rather than constructing a formal interfuel substitution model based on historical data (Silverman et al. 1982). The other major baseload fuel is gas and it is largely restricted to the South-Central states. Initially it appeared that both gas and oil commitments would be totally policy determined by the 1978 Powerplant and Industrial Fuel Use Act. Accordingly, our focus here has been again on identifying the characteristics of existing capacity and planned commitments.

As late as the mid-1970s many analysts were predicting 1000 gigawatts (GW) of nuclear capacity by the year 2000. The actual on-line capacity plus reactors under construction or review peaked in 1976 at 237 GW and has fallen every year since. It now appears unlikely that more than 185 GW will be on line in the year 2000. The early optimism surrounding nuclear power was apparently fueled by manufacturers' advertisements that passed for analysis, with the Atomic Energy Commission and later ERDA acting as cheerleader. Because of commitments in the early 1970s, over 25% of the new capacity coming on line in the 21-state NGP market area by 1990 is nuclear. However, after 1990 it is doubtful that any additional nuclear plants will be coming on line before the year 2000. This drastic turnaround is due to a number of factors: the cost overruns of earlier turn-key plants were not well reported or closely analyzed; the public's latent fears about the new technology have been reinforced by Three Mile Island; more stringent regulatory standards have added to increased costs; and finally there continue to be unresolved questions about both ends of the nuclear fuel cycle (uranuim supply and permanent waste disposal).

Ten utilities in the 21-state NGP market area have cancelled or indefinitely deferred plans for new reactors since 1976. Representatives of eight of these utilities were contacted to assess their reasons for cancellation or deferral (Silverman et al. 1982). The utilities reporting cancellations included the owner/operators of some of the most successful commercial reactors in the country, including Commonwealth Edison and Northern States Power; these utilities as well as most of the others contend that nuclear power is still cheaper than coal. The most common reason for cancellation is not costs but declining demand. In the face of uncertain load growth, nuclear power is a much riskier investment than coal due to 10- to 12-year construction and licensing lead times and the large capital commitment. The reactors cancelled were on the order of 1200 mW capacity each; those being replaced will present plans for 500- to 650-mW coal plants.

Three representatives of the utilities interviewed cited regulatory uncertainties as the reasons for canceling: these included "anti-nuclear" attitudes of regulators or directors, shifting regulatory requirements that lead to cost uncertainties, the potential for a de facto licensing moratorium (as after Three Mile Island), and delays and financial risk associated with waste disposal. One utility representative cited capital formation problems. Only one utility spokesperson said that litigation and public opposition had directly led to cancellation (Indiana Public Service's Bailly Nuclear I, which began construction in 1974 adjacent to the Indiana Dunes on Lake Michigan).

While not surveyed, an eleventh recent cancellation in the region is the Washington Public Power Supply Systems WPPSS #4 and #5. The fundamental problems appear to be mismanagement, slow load growth, cost overruns, and resulting severe capital formation constraints.

Gas rather than oil is a major boiler fuel in the current NGP market area (25% of the total 1979 generation) and this use is largely limited to the South-Central states of Oklahoma, Texas, and Louisiana. To explore the impacts of market-based substitution between gas and coal, we examined the actual on-line capacity and various assumptions regarding likely retirement dates for existing capacity (Silverman et al. 1982). In addition, a major concern of that study was to identify the likely impacts of Federal policy in this area.

Beginning with the passage of the Energy Supply and Environmental Coordination Act of 1974, the Federal government has tried to mandate the conversion of oil- and gas-fired boilers to coal. The Powerplant and Industrial Fuel Use Act of 1978 enhanced Federal powers to require fuel switching. An unsuccessful proposal, the Powerplant Fuels Conservation Act of 1980 would have offered as much as $10 billion to subsidize power plant conversions to coal. The eight-year-long progression of these attempts to legislate fuel switching and rapid fuel substitutions has produced mixed results. In fact, the entry of Federal law and policy into the power plant fuels market has probably served to lower the total amount of petroleum burned by utilities, but it has raised the consumption of natural gas. Meanwhile, the effect of Federal policy and law on conversions to coal and other fuels has fallen far short of past congressional and administrative goals. In the 21-state Northern Great Plains coal market area, the potential effect of Federal policy and law might have become significant, raising total coal demand within the market area by approximately 13 mmt/yr. But administrative and statutory changes have now guaranteed that enforcement of Federal fuel-switching objectives will not occur.

ELECTRIC UTILITY STEAM COAL FORECAST

Forecast Results

One of the main objectives of this paper is to identify the relationship between key political and economic factors and the future level of demand for NGP coal. As noted previously, the impact of various parameters is synthesized through (1) defining the spatial market, (2) electric consumption growth rates for that market, (3) interfuel substitution (nuclear power, oil, gas, hydroelectricity, and coal), and (4) intrafuel substitution (NGP vs. competing coals in the NGP market area). The general strategy was to forecast electrical consumption for the 21-state area, subtract out 1979 generation, and allocate new generation capacity among nuclear power, hydroelectricity, oil, gas, NGP coal and other coals.

More specifically, steps one and four of the forecast were resolved simultaneously in two alternative ways. The first approach was to use the NGP population-weighted spatial market. In Table 3, the NGP coal production forecasts based on this approach are summarized. The spatial markets derived by Silverman et al. (1982) yield the share of a given state's population that is within the NGP market boundary in a given year. This share was used to allocate the incremental growth in coal-fired generation for a given forecast period between NGP and competing coals. For example, the forecast in 1990 includes plants that came on line between 1979 and 1990. The 1980 market boundary is used in this case to approximate the conditions under which representatives of utilities made decisions for this generation of plants. Similarly, the 1990 spatial market is assumed representative for plants coming on between 1990 and 2000; the same is true for the period 2000 to 2010. As apparent in Figure 2, the base case spatial market is predicted to shrink somewhat over time.

The alternative approach to defining the spatial market and the NGP coal share within that market is to simply assume that the NGP share will be constant for a 21-state area at the actual contract share for new and proposed plants for the period 1976-1990 (58%). Findings for this approach for various electric growth rates are summarized in Table 4. A comparison of Tables 3 and 4

TABLE 3. SUMMARY OF NGP COAL FORECASTS BY YEAR: SPATIAL MARKET AND ELECTRIC GROWTH SENSITIVITY[1]

		Electric Growth Scenario			
		SLED[2]			Constant 3% to 2000; 1.9% after 2000
Year	Spatial Market Case	Low	Base	High	
1990	Low	124,549	137,370	152,002	130,063
	Base	131,005	145,187	161,222	135,140
	High	144,990	165,534	188,016	144,812
	Current	158,922	179,551	202,080	150,440
2000	Low	135,567	158,779	187,969	164,291
	Base	145,890	172,637	205,710	176,533
	High	242,597	297,580	360,132	261,264
	Current	297,027	374,556	460,331	309,069
2010	Low	155,308	174,073	197,616	175,860
	Base	176,942	202,948	235,593	208,048
	High	322,121	378,705	444,095	345,743
	Current	478,927	572,316	675,645	493,068

[1] Figures in thousand tons/year.
[2] State Level Electric Demand (Model).

TABLE 4. SUMMARY OF NGP UTILITY COAL FORECAST BY YEAR: CONSTANT CONTRACT SHARE, ELECTRIC GROWTH SENSITIVITY[1]

Electric Growth Scenario	Year 1990	 2000	 2010
SLED			
Low	169,869	350,946	563,812
Base	195,977	435,137	665,499
High	223,442	523,843	772,516
Constant (percent)[2]			
2.5	135,558	275,850	473,225
3.0	155,926	335,796	545,584
3.5	180,178	401,854	625,322

---

[1] NGP share of coal in market area constant at 58%; figures are in thousand tons/year.

[2] Growth rates are to 2000; thereafter 1.9%.

indicates that estimates are about doubled by a continuation of current contract shares. We have little confidence in the latter method, as actual contracts between 1979 and 1990 were based on air pollution control policy, labor and rail costs, and other factors that have changed substantially. Table 4 is included here primarily to illustrate the sensitivity of production levels to growth in electrical consumption when other factors are held constant.

In addition, there are two alternative approaches to electric forecasts: (1) state-specific, price-sensitive forecasts based on the SLED model and (2) constant annual growth in electric consumption of 2.5%, 3.0%, and 3.5% to 2000 and 1.9% thereafter. As Table 4 indicates, a 1% difference in the growth rate in electrical consumption results in a 45% difference in the coal production forecast in the year 2000. The SLED base case results in an average forecast for the market area of 3.44% to the year 2000 and is about the same as the constant 3.5% forecast.

The forecasts included in Table 3, based on the spatial market model, are our best estimate of the most likely levels of future production. A major finding is that our estimate of firm contracts for 1985 production (182 mmt/yr) is consistent only with the upper range of plausible electric consumption growth rates and spatial market size. Our forecasts for 1990 in Table 3 range from 124 mmt/yr to 202 mmt/yr. Even assuming future current share of contracts and the highest electric growth scenario (Table 4), production would be no higher than 223 mmt/yr. In order to get the high range in either a population-weighted or a constant share case, we have to assume the SLED high forecast (about 4%/yr) is valid, which is unlikely, and that the market is based on the "current" spatial market scenario (Table 3), which assumes no real escalation in rail or labor costs for 35 years. The implications of this finding are either that (1) utility representatives are ignoring real escalation in their fuel choices or are heavily discounting the future in their decisions, or (2) there will either be slippage in the coal plants coming on line or overcapacity for some years beyond 1990, or (3) we are badly underestimating either growth in electrical consumption or the spatial market size.

Variations on Forecast Results

In general, Table 3 indicates that the sensitivity of the forecast to the plausible range of electric consumption growth rates is about the same as sensitivity to the plausible range of low, base, and high spatial markets. This is illustrated in Figure 3 in a comparison of the base case spatial market and the high spatial market case.

In interpreting the spatial market permutations, it should be noted that the low and high scenarios were generated rather mechanically by 95% confidence intervals on year 2000 trend estimates. It was assumed that "high" labor would be associated with "high" everything else, including rail. It is possible that even the considerable range in coal production levels due to spatial market permutations in Table 3 understates over time the potential volatility of these markets. For example, when we changed a single parameter in our "current" (no escalation) market scenario and we assume rail would escalate at its "low" historical trend of 2.8%/year, the year 2000 forecast for the SLED base scenario shrinks from 374 mmt/yr to 153 mmt/yr.

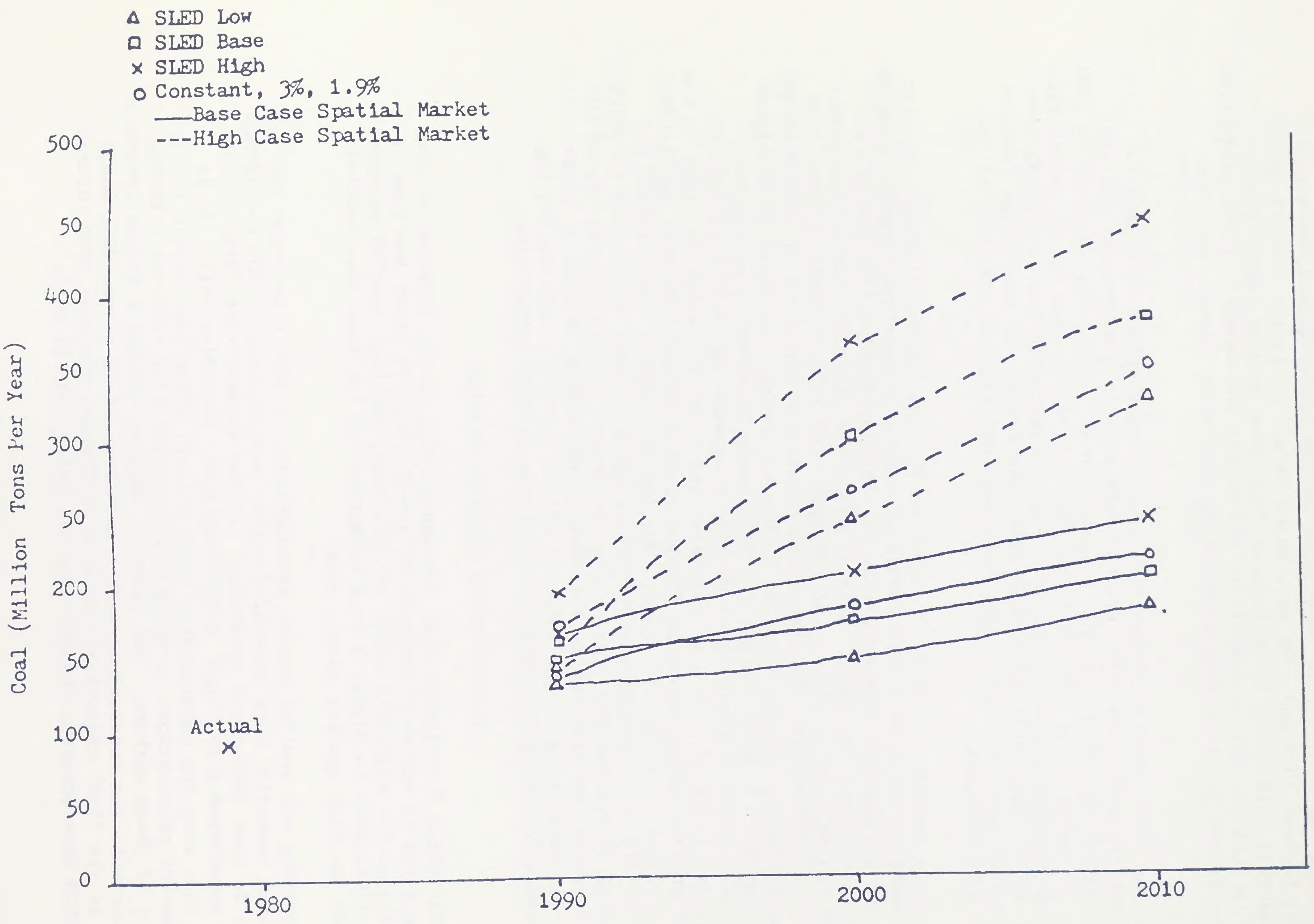


Figure 3. Comparative sensitivity of growth rates and spatial market case: utility coal demand (Silverman et al. 1982.).

For very extreme changes in any parameters, there are probably offsetting linkages that moderate the effects. A direction for further research would be to explore the simultaneous relationships of product and factor prices in the coal industry. In addition, we have ignored the impacts of reserve depletion on coal prices. Given the magnitude and quality of reserves relative to the time period and annual production forecasts, this is likely to be a minor factor. The exception might be for Texas lignites and Washington state coal. This, however, could be of limited practical significance as new rail facilities will probably enable New Mexico to dominate the Texas market, and southern Wyoming or Utah coal could capture most of the Washington-Oregon market.

We also examined the effect of very low electric consumption growth rates: 2% to 1990 and 0.5% thereafter. SERI views these levels of consumption growth as a plausible outcome of policies favoring conservation and renewables. For the likely range of spatial markets, this would limit utility steam coal to 120 mmt/yr to 171 mmt/yr out of the NGP in the year 2010.

The results summarized here are also dependent on the following interfuel substitution assumptions: (1) there are no changes in baseload hydroelectric capacity in the market area, (2) only nuclear reactors now on line, under construction, licensing review, or on order will be on line to 2010, (3) no new oil- or gas-fired utility boilers will be built before 2010, (4) existing baseload gas and oil will be on line throughout a 40-year life and then replaced with coal. Our assessment of hydroelectric and nuclear power led us to conclude that no significant changes were likely in the forecast period for these types of capacity. However, one permutation for oil and gas was explored--instead of assumption (4) above, all base and intermediate load oil and gas would be replaced by coal by 1995. Our review of mandatory fuel-switching policy indicates that the latter scenario is rather unlikely. In any case, its impact was to increase coal production (Table 3) for the base case in year 2000 by only 2% to 4%. The effect in 1990 and 2000 was, therefore, negligible. The minimal impact is partly because major baseload capacity is limited to the South-Central states, such as Texas and Louisiana, that are out of our market area in most forecast years. Even if these states were entirely within the market, the impact would be no more than 64 mmt/yr for the years near 2000.

Limiting our analysis to date is that we have not investigated the possible reallocation of existing coal capacity upon retirement. This would require a survey of the likely date of technical and economic obsolescence for coal-fired plants now on line in the market area. Given that the NGP share of the market for incremental capacity is greater than its historical share, this omission probably biases our results downward by an unknown amount.

The most likely range of forecasts for utility steam coal is summarized after the following description of other potential markets for NGP coal.

INDUSTRIAL, EXPORT, AND SYNFUEL MARKETS FOR NGP COAL

Industrial Coal

While the current market for NGP coal is largely dominated by electric utility steam coal purchases, there may be a large potential for industrial, export, and synfuel uses. Coal's share of the industrial energy market declined from 20% in 1954 to 6% in 1980. However, it is expected that coal use will rebound in the future due to the steep increase in oil and natural gas prices. The consensus is that coal will find limited use in process heat applications for glass, food, and textiles, which require clean-burning fuels; the major expansion in coal use is expected for cement and lime kilns. The other major industrial energy use is in boilers; since about 90% of existing boilers cannot be easily retrofitted to coal, increased use of coal will be limited to large new boilers. The extent to which coal penetrates this market will depend on the economics of competing fuels, mandatory coal use regulations, and air pollution standards.

Considering these factors, two major, recent national studies arrive at very different conclusions. The Department of Energy expects annual industrial coal use (including metallurgical coal) to reach 7.3 quads in 1990. The National Coal Association (NCS) is forecasting a level of about half this, or 125 mmt (compared to the NCA 1979 estimate of 74 mmt).

A. Silverman et. al. (1982) surveyed 48 known industrial coal users (in the 21-state NGP utility market area) and all 24 known NGP coal producers as to the future of industrial coal. The response rates were 46% and 67%, respectively. Unfortunately, many of the responses were only partially complete because of an unwillingness to provide price and cost information.

For the entire 21-state area, 25 of 48 industrial users employed coal for process heat and the remainder used coal boilers. Consistent with the national picture, the bulk of process heat applications (14 of 25) were for cement and lime kilns; this industrial coal use in the 21-state area usually totaled only 6.0 mmt (a small fraction of total industrial coal use in the 21-state area). Of our sample total, only 25%, or 1.5 mmt, was supplied by NGP mines and was consumed in a much smaller 8-state (Montana, North and South Dakota, Wyoming, Colorado, Nebraska, Minnesota, and Wisconsin) "industrial" coal market area. The smaller market is due largely to the (approximately) doubled single car or truck rates for industrial coal shipments when compared to unit train rates. In contrast to the national industrial coal market, NGP industrial coal use is largely for boilers in the Red River and Billings area sugar refineries. NGP coal used in cement and lime kilns is limited to a single plant in Rapid City, South Dakota. This is due to the preference for a minimum 9,800 Btu/lb coal to maintain flame temperatures and a limitation on moisture content. These technical constraints can be overcome, but as substantial capital costs. Montana cement plants currently import higher Btu Utah and southern Wyoming coals.

We also reviewed three studies of the comparative economics of coal, oil, and natural gas in industrial fuel boilers (Silverman et al. 1982). For comparison, the study results were revised to constant 1980 dollars for the same boiler class size (175 mm Btu/hr) and for NGP-delivered coal costs. The basic finding is that oil is clearly no longer a competitive fuel for industrial boiler applications. However, the results for coal and gas in terms of total life cycle costs are very close; in fact the conclusion as to the least-cost fuel varies across the studies. The tradeoff is larger capital expenditures for coal versus more expensive fuel for gas-fired boilers; approximately 80% of the annualized cost of gas-fired boilers is for fuel versus approximately 30% for coal. Accordingly, the results are sensitive to assumed fuel price escalation, capacity factor, capital recovery factor, and payback. Generally, for paybacks of less than 10 years, gas is the least-cost choice.

The choice is complicated by the Powerplant and Industrial Fuel Use Act, which requires that coal must be the boiler fuel in units greater than 100 mmBtu/hr unless coal is "comparatively more expensive." The extent to which compliance will be evaluated or enforced is uncertain. In addition, the results reported above assume compliance to New Source Performance Standards for sulfur dioxide emissions, which increase capital costs for coal by about one-third.

The conclusion of the industrial coal use analysis for the NGP is that at present this use is a minor component (about 4%) of total demand. Given the technical limitations on the use of most NGP coals for many process heat applications and the uncertain cost advantage in coal boilers and the small market area, industrial use of NGP coal is likely to remain quite modest for the foreseeable future.

Export Market

Because of the NGP location vis-a-vis port facilities, the potential NGP export market is to the industrialized Pacific Rim countries: Japan, South Korea, Taiwan, and Hong Kong. In 1980, these countries imported approximately 90 mmt, of which approximately 95% was metallurgical coal. However, most analysts expect a rapid increase in steam coal imports by these countries, reaching perhaps 200 mmt by the year 2000. This projected demand is in response to multiple increases in world oil prices.

The major exporters to the Pacific Rim are currently Australia, South Africa, Canada, and the U.S. A simplified spatial market analysis shows that delivered costs to Japan (in dollars per million Btu) for the major competing coals are Australia, $1.22; South Africa, $1.50; China, $2.00; Canada, $2.55; and western U.S. coals, $2.04 to $2.36 (Silverman et al., 1982). Clearly, Australian and South African coals are least cost. However, the Japanese, with 95% of their energy imported, are interested in diversifying their energy sources to reduce the risk of supply interruptions and price changes. Part of their motivation is related to a 1980 Australian labor strike that essentially stopped the bulk of Japanese coal imports. The U.S. in contrast is viewed as a relatively secure supply source.

The Japanese are expected to contract for some western U.S. coal as part of their diversification strategy. At present, most of this coal would probably come from Utah, which is least cost for Pacific Rim export through California ports and has a Btu content and other qualities that most closely match Australian coal. This means that Utah coal can be readily substituted in existing Japanese boilers--an essential element in a diversification strategy. The near-term market for NGP coal is limited by the fact that existing Pacific Rim utilities cannot burn the high moisture and relatively low Btu coal. In any case, NGP exports would not be feasible until coal port facilities are completed, perhaps in the late 1980s, at Portland, Oregon, and/or Kalama, Washington. Our expectation is that there may be very minor export of some NGP steam coal for industrial use in 1990 and possibly 13 mmt/yr to 26 mmt/yr by 2000 A.D. However, depending on development of port facilities and public attitudes toward coal export, the huge NGP reserve base may lead to a substantial export market in the 21st century.

COAL-BASED SYNTHETIC FUELS

Interest in synthetic fuels in this country dates back to World War II, but practical implementation was hindered by the cheap and abundant oil and gas of the post-war years. As the pattern of rapid price increases and corresponding conservation and exploration of the 1970s settles into a period of slower but steady increases in oil prices, there is a growing interest in synthetic fuels from oil shale and coal. The main determinants of the timing and structure of synthetic fuel development are the price of oil and the level of Federal guarantees. The Carter program as embodied in the Energy Security Act of 1980 was overly ambitious and would have resulted in an overwhelming reliance on first-generation, relatively inefficient technology, with inadequate environental planning. The current administration places greater emphasis on private sector investment through decontrol of fuel prices and a more ready access to the resource base, plus some Federal guarantees, research investments, and tax restructuring to encourage long-term risk-taking.

Water is clearly a limiting factor in the western oil shale fields; accordingly, syncrude from coal looks potentially attractive. However, the existing technology is both first generation and expensive, and water is also a problem for western coal-based synfuels. We expect that the key to a commercial synfuels industry after the year 2000 depends on developing efficient, second-generation technologies that can produce fuels at $5.00 to $7.00/mmBtu in 1982 dollars.

The synfuel forecasts of the 1970s were premised on a major national commitment and continued high energy consumption growth rates. In 1976 ERDA forecast synfuel coal demand in the NGP of 18 mmt/yr in 1985, 70 mmt/yr in 1990, and 225 mmt/yr in the year 2000. The latter represented 45% of the total national liquid synfuel forecast, including oil shale. The water requirement of such a program would be 1.4 mm ac-ft/yr by 2000 A.D. beyond an existing 3.0 to 4.0 mm ac-ft/yr obligation. The average annual low water flow on the Missouri River at Sioux City, Iowa, is 6 mm ac-ft. Under the ERDA scenario for the year 2000 the Missouri would be 65% depleted in average low water years; and in extreme years it would be dry. More recent national forecasts by CONAES (1978) and the U.S. Department of Energy (1981) are somewhat lower, but they still expect very significant coal demand by the year 2000 (DOE expects 135 mmt/yr to 415 mmt/yr nationally).

Six years ago, in a regional forecast for the NGP, we projected a lack of synfuel development before 1990 in Montana, Wyoming, and North Dakota (MUCDS

1976). That study concluded that for the decade 1990-2000, development was possible but not assured and that the factors controlling synthetic fuel development were not well enough known to forecast. The present situation is not much different--oil prices are higher, but remain uncertain; water rights adjudication, constraints on interbasin transfer, instream flow requirements, and concerns about ground-water quality, quantity, and use could severely limit a coal-based energy industry. National policy and market response to conservation and renewables will all determine the energy mix of the 21st century and the synfuel future.

We expect that there will be no synfuel plants in the NGP or the country before 1986. Facilities on line in 1985-1995 will be at a few well-chosen sites to demonstrate a range of technologies. By 2000, only three or four plants sited in the NGP and producing a total of 150,000 to 200,000 bbl/day oil equivalent will require 15 mmt to 20 mmt of NGP coal per year. Two or three of these plants will be syngas and one may be syncrude; one will be in North Dakota and perhaps one in Montana; the rest will be in Wyoming. Anticipated State and local constraints on social and environmental impacts would limit additions to the year 2010 to 6 to 12 new plants (45 to 80 mmt/yr coal). These forecasts are a small fraction of the production levels predicted by DOE; however, they reflect better the realities of building and operating large, complex, expensive, and resource-demanding facilities in the NGP.

By 2000 A.D., we might be exporting an additional 15 mmt/yr to 20 mmt/yr to synthetic fuel plants outside the NGP states and by 2010, as much as 80 mmt/yr, which implies a total NGP synfuel demand of 0 in 1990, 30 to 30 mmt/yr in 2000, and 90 to 160 mmt/yr in 2010. It must be remembered that these numbers are very speculative.

COMPARISON TO OTHER FORECASTS

The "most likely" range forecast for NGP coal demand is summarized in Table 5. The high end of the utility steam coal forecast is based on the view that (1) it is very doubtful that electric growth over the forecast period will be above the SLED base case, which is about 3.4% per year to 2000 and 1.9% thereafter, and (2) the market area will almost certainly not be greater in the future than the "current" spatial market case, which assumes no real escalation in rail or labor costs. Acknowledging these constraints, the high in the year 1990 is based on the SLED high (Table 3), which is probably too large. The high for the year 2000 is the SLED base case (from Table 3), and high in 2010 is the constant 3% and 1.9% growth scenario.

The floor in 1990 and 2000 for utility coal is the SLED base and the base case spatial market and the SLED low and base case spatial market, respectively, each at 145 mmt/yr. This implies slippage and cancellation in the amount of 40 mmt/yr from even the 1985 contract estimate of 182 mmt. It is conceivable, in the face of even moderate rates of electric growth, that no additional capacity would be needed to the year 2000. The low in 2010 A.D. is taken as the base case market for the SLED low case. The industrial export and synfuel estimates are derived as discussed above. We anticipate, therefore, total NGP coal production (in mmt/yr) of 151 to 210 in 1990, 194 to 455 in 2000, and a rather speculative 289 to 723 in 2010.

TABLE 5. COAL USE FORECAST FOR THE NORTHERN GREAT PLAINS (COMPARISON)*

Forecast/Market	Year 1985	1990	1995	2000	2010
A. Montana University Coal Study					
Electric Utility		145-202		145-374	177-493
Industry		6-8		6-15	7-20
Export				13-26	15-50
Synthetic Fuels				30-40	90-160
Total		151-210		194-455	289-723
B. U.S. Department of Energy (1981)					
Residual (Utility plus industry)	203-239	194-401	253-739		
Synthetic Fuels	12	32-43	42-141		
Total	215-251	226-444	295-880		
C. ICF, Inc. (1980)					
Electric Utility	153-213	171-395	173-607		
Industry	2	3	4		
Synthetic Fuels	6	16	32		
Total	161-221	190-414	209-643		

* Figures are in million tons/year.
Source: U.S. Department of Energy 1981d, and ICF, Inc. 1980c.

These results can be contrasted with recent forecasts by U.S. Department of Energy (1981) and ICF, Inc. (1980). The U.S. Department of Energy's forecast was made in 1981 as a basis for leasing policies for Federal coal. The low and high cases are premised on a 2.25% to 4.4% growth rate in electrical consumption. Even though DOE's low in 1990 (226 mmt/yr) is based on 2.25% growth, it is slightly larger than the upper end of our high range (210 mmt/yr) based on about a 4%/year electric comsumption growth rate (SLED high). There is insufficient documentation available to determine the reason for the substantial difference in forecast levels between our study (151 to 210 mmt/yr and DOE 226 to 444 mmt/yr). Synfuels is clearly overforecast by DOE, but whether the difference in the "residual" component (industrial and utility) is due to implicit spatial market, interfuel substitution, or other factor differences is uncertain. We would have difficulty constructing a set of conditions that could generate a forecast of 400 mmt in 1990 for utility plus industrial coal.

The ICF forecast just overlaps the high end of our forecast for 1990. Their base case assumed 3.5% electric growth to 1985 and 3% thereafter. Some of the 54 mmt difference between ICF's 3.5% growth case and ours is due to differences in projected nuclear power and hydroelectric capacity. However, most of the difference is probably due to implicit market size. In addition, our forecasts for total tonnage appear to lag the ICF forecast by appoximately 5 years in the near term, 10 years in the middle term, and increases to 15 years in the out-years.

In all likelihood the high end of future DOE and/or ICF forecasts will decrease in response to the most recent trends in electrical consumption and as the scope of the near-term Federal synfuels program is better defined. However, aside from these factors, there appears to be a consistent tendency for most investigators to overforecast NGP coal demand, which might be due to a lack of understanding of the determinants of the spatial market.

To the extent that our model is accepted as a sufficiently realistic characterization of the market for NGP coal, it provides a useful tool for analyzing certain aspects of State and Federal energy policies. These policies include: Federal leasing policies, State coal taxes, reclamation and transportation regulation, competition in the coal industry, fuel switching, sulfur dioxide air pollution regulations, and Federal subsidy and regulation of nuclear and synthetic fuel plants.

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MIDWESTERN AND EASTERN COAL DEVELOPMENT PERSPECTIVES

by

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Coal is the most abundant of America's fossil fuels. Coal resources in the U.S. are estimated to be over 4 trillion tons, proven resources are approximately 1.2 trillion tons, mineable resources about 438 billion tons, and recoverable resources around 250 billion tons. The recoverable resources of coal contain the energy equivalent of 1,000 billion barrels of oil. That is more than six times America's recoverable crude oil resources (Two Energy Futures: A National Choice for the 1980s 1980).

The use of coal as a transition fuel to renewable energy sources seems irresistible. However, coal has tremendous environmental problems associated with its development. Since more than half the mineable coal resources in the country lie west of the Mississippi River, and since these coal resources have yet to undergo full development, it seems wise to look at the historical record of coal use in the East and Midwest to gain perspective and identify potential problems which must be avoided in western coal development.

FUTURE U.S. COAL DEVELOPMENT PATTERNS

While more than half the U.S. coal resources lie in the West, western coal is largely subbituminous and has a lower heat value content per weight than eastern and midwestern coal. For example, western coal has an energy equivalent of roughly three barrels of oil per ton. Appalachian and midwestern coal is bituminous and contains an energy equivalent of four barrels of crude oil. Thus, while there is less tonnage available in the East and Midwest, the energy yield per ton is higher in the East. Certainly the most important fact about coal, and all other energy sources, is not the total resource available in the ground, but the ultimate net energy yield from that resource. In Table 1, the classifications of coal are examined. Coal is carbonaceous rock derived from vegetative debris buried and altered by earth pressure and chemical processes. As water and volatile matter are squeezed out, the vegetative debris changes from peat to lignite to bituminous coal. Additional heat and pressure change bituminous coal into anthracite.

These coals have the following characteristics:

Lignite.--A low-ranking, brown-to-black coal that contains a high percentage of moisture and less than 8,300 Btu's. When lignite is exposed to air it loses moisture and crumbles, so precautions have to be taken to store it satisfactorily.

Bituminous.--The most abundant variety of coal and the only type mined in the East and Midwest. This coal ranges from medium to high rank. Subbituminous coal has a Btu rating between 8,300 and 11,000. The maximum rating of bituminous coal is 14,000 Btu's.

Anthracite.--A hard coal with a brilliant luster. It can be rubbed without leaving a mark on the finger, polished, and made into costume jewelry. Anthracite burns slowly with a pale blue flame that requires little attention. It has at least a 14,000 Btu rating and is primarily used as a domestic fuel, but can sometimes be blended with bituminous coal for industrial use.

TABLE 1.--CLASSIFICATION OF COALS BY RANK

Class	Group	Fixed carbon limits, percent (dry, mineral-matter-free basis)		Volatile matter limits, percent (dry, mineral-matter-free basis)		Calorific value Btu's pound (moist, mineral-matter-free basis)		Agglomerating character
		Equal or greater than	Less than	Greater than	Equal or less than	Equal or greater than	Less than	
I. Anthracitic	1. Meta-anthracite	98	--	--	2	--	--	Nonagglomerating
	2. Anthracite	92	98	2	8	--	--	
	3. Semianthracite	86	92	8	14	--	--	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	--	--	Commonly agglomerating
	2. Medium volatile bituminous coal	69	78	22	31	--	--	
	3. High volatile A bituminous coal	--	69	31	--	14,000	--	
	4. High volatile B bituminous coal	--	--	--	--	13,000	14,000	
	5. High volatile C bituminous coal	--	--	--	--	10,500	11,500	Agglomerating
III. Subbituminous	1. Subbituminous A coal	--	--	--	--	10,500	11,500	Nonagglomerating
	2. Subbituminous B coal	--	--	--	--	9,500	10,500	
	3. Subbituminous C coal	--	--	--	--	8,300	9,500	
IV. Lignitic	1. Lignite A	--	--	--	--	6,300	8,300	
	2. Lignite b	--	--	--	--	--	6,300	

(Source: Cook 1979).

TABLE 2.--DEMONSTRATED RESERVE BASE OF COAL IN THE UNITED STATES BY RANK*

State	Anthracite	Bituminous	Subbituminous	Lignite	Total
Alabama	-	5,676.8	-	1,083.0	6,759.8
Alaska	-	697.5	5,444.0	14.0	6,155.5
Arizona	-	424.3	-	-	424.3
Arkansas	96.4	289.0	-	25.7	411.0
Colorado	25.5	9,106.3	4,117.3	2,965.7	16,214.8
Georgia	-	3.7	-	-	3.7
Idaho	-	4.4	-	-	4.4
Illinois	-	67,705.0	-	-	67,705.0
Indiana	-	10,621.1	-	-	10,621.1
Iowa	-	2,198.6	-	-	2,198.6
Kansas	-	994.8	-	-	994.8
Kentucky, East	-	13,098.2	-	-	13,098.2
Kentucky, West	-	21,141.9	-	-	21,141.9
Maryland	-	826.2	-	-	826.2
Michigan	-	127.7	-	-	127.7
Missouri	-	6,077.2	-	-	6,077.2
Montana	-	1,385.4	103,317.8	15,765.7	120,468.8
New Mexico	2.3	1,842.6	2,696.6	-	4,541.5
North Carolina	-	10.7	-	-	10.7
North Dakota	-	-	-	9,971.2	9,971.2
Ohio	-	19,034.7	-	-	19,034.7
Oklahoma	-	1,644.0	-	-	1,644.0
Oregon	-	-	17.5	-	17.5
Pennsylvania	7,095.7	23,332.1	-	-	30,427.8
South Dakota	-	-	-	366.1	366.1
Tennessee	-	997.7	-	-	997.7
Texas	-	-	-	12,693.5	12,693.5
Utah	-	6,500.5	1.1	-	6,501.6
Virginia	125.5	3,412.4	-	-	3,537.9
Washington	-	255.3	1,316.8	8.1	1,580.2
West Virginia	-	39,984.9	-	-	39,984.9
Wyoming	-	4,482.0	65,532.0	-	70,014.0
Total	7,345.4	241,875.0	182,443.1	42,893.0	474,556.5

*As of January 1, 1979; figures in million short tons.

Source: Demonstrated Reserve Coal Base of Coal in the United States on January 1, 1979. 1981.

Table 2 shows the geographic distribution of coal by type. Lignite reserves are completely unimportant east of the Mississippi River. In contrast, while more widely distributed geographically, the largest tonnage reserves of bituminous coal lie in the eastern and midwestern States.

While western coal is at a disadvantage where simple Btu analysis is concerned, it has other advantages. Generally, western coal is cheaper and less energy consumptive to mine, largely uses non-union labor, and is lower in sulfur content. Western coal ranges from 0.2% to 0.7% sulfur, while midwestern and Appalachian coal can range as high or higher than 3% or 4% sulfur.

The current debate in the country over the Clean Air Act would then seem to play a role in the future of coal development patterns. If the Clean Air Act standards regarding sulfur dioxide emissions are relaxed, eastern and midwestern coal could regain a firmer competitive position. If the Clean Air Act remains intact, western coal would seen to have the competitive advantage.

Current coal activity is mainly concentrated in the East and Midwest. In 1979, 72% of U.S. coal production was in the Appalachian and midwestern region. In 1979, Kentucky was the leading coal-producing State with nearly 20% of the total U.S. output. West Virginia and Pennsylvania were next, providing a combined 25% of total production (Two Energy Futures: A National Choice for the 1980s 1980).

If full development of western coal is realized, these figures could change dramatically in the 1980s and 1990s. Citizens in the western U.S. owe it to themselves to assure that this development, if it indeed does take place, occurs in the most environmentally compatible manner possible.

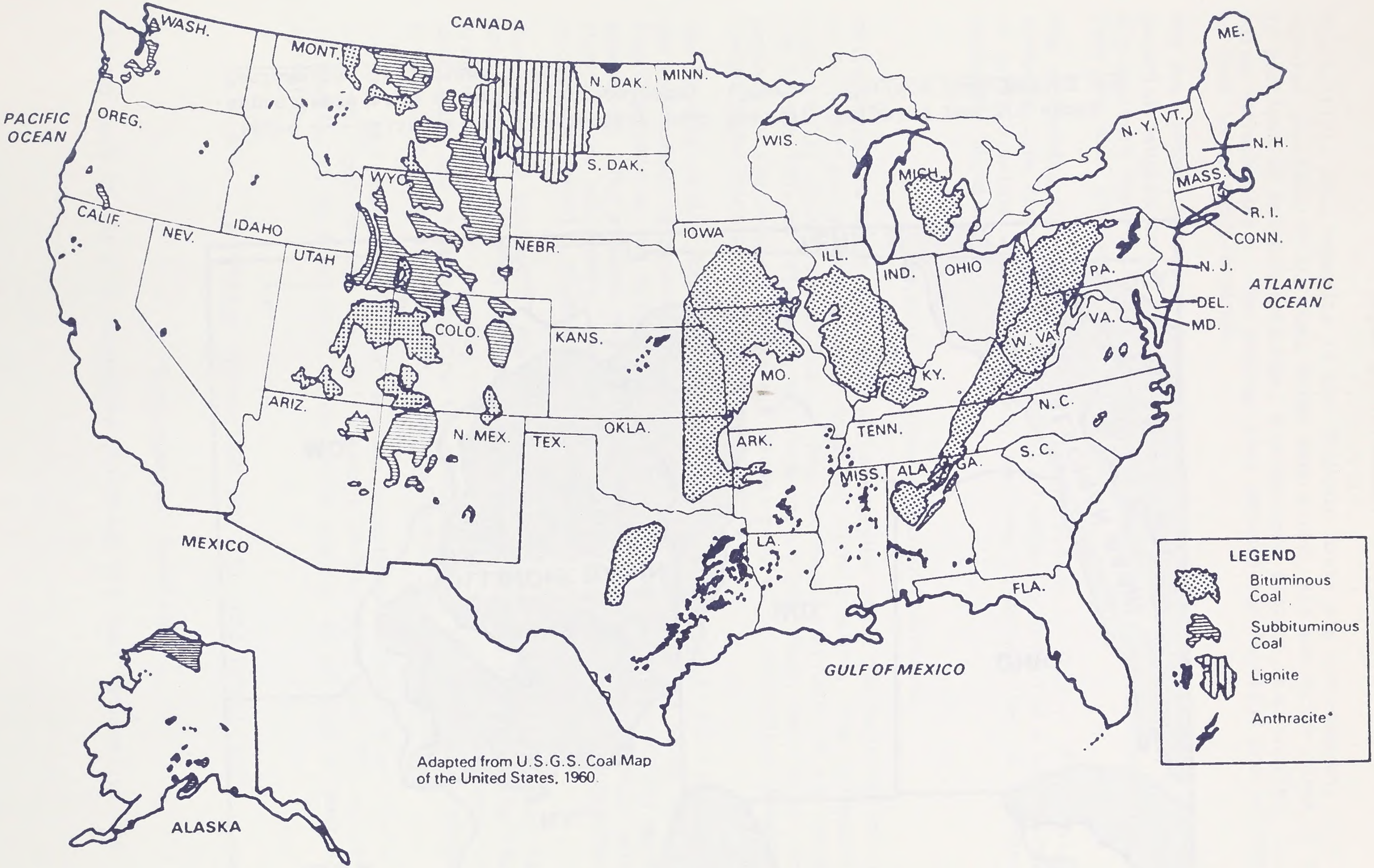
EXTENT AND CHARACTER OF MIDWESTERN COAL RESOURCES

Geographic Characteristics of Coal Deposits

Midwestern coal is normally defined as those deposits located in the Interior Coal Basin (Fig. 1). The Interior Basin is divided into two parts. This paper will deal with the section contained in Illinois, southwestern Indiana, and western Kentucky commonly known as the Illinois Basin (Fig. 2). Indiana will be selected as a case study.

The topography of this area is flat or gently rolling. The soils are generally excellent for agricultural use, and many are classed as prime farmlands.

While one of the major limiting factors in coal development in the West is inadequate water, one of the major limiting factors in using midwestern coal is the prime farmland question. How sensitive the midwestern States are to these prime farmlands should play a major role in the future use of these coal resources.



Adapted from U.S.G.S. Coal Map of the United States, 1960.

Figure 1. Coal basins of the United States.

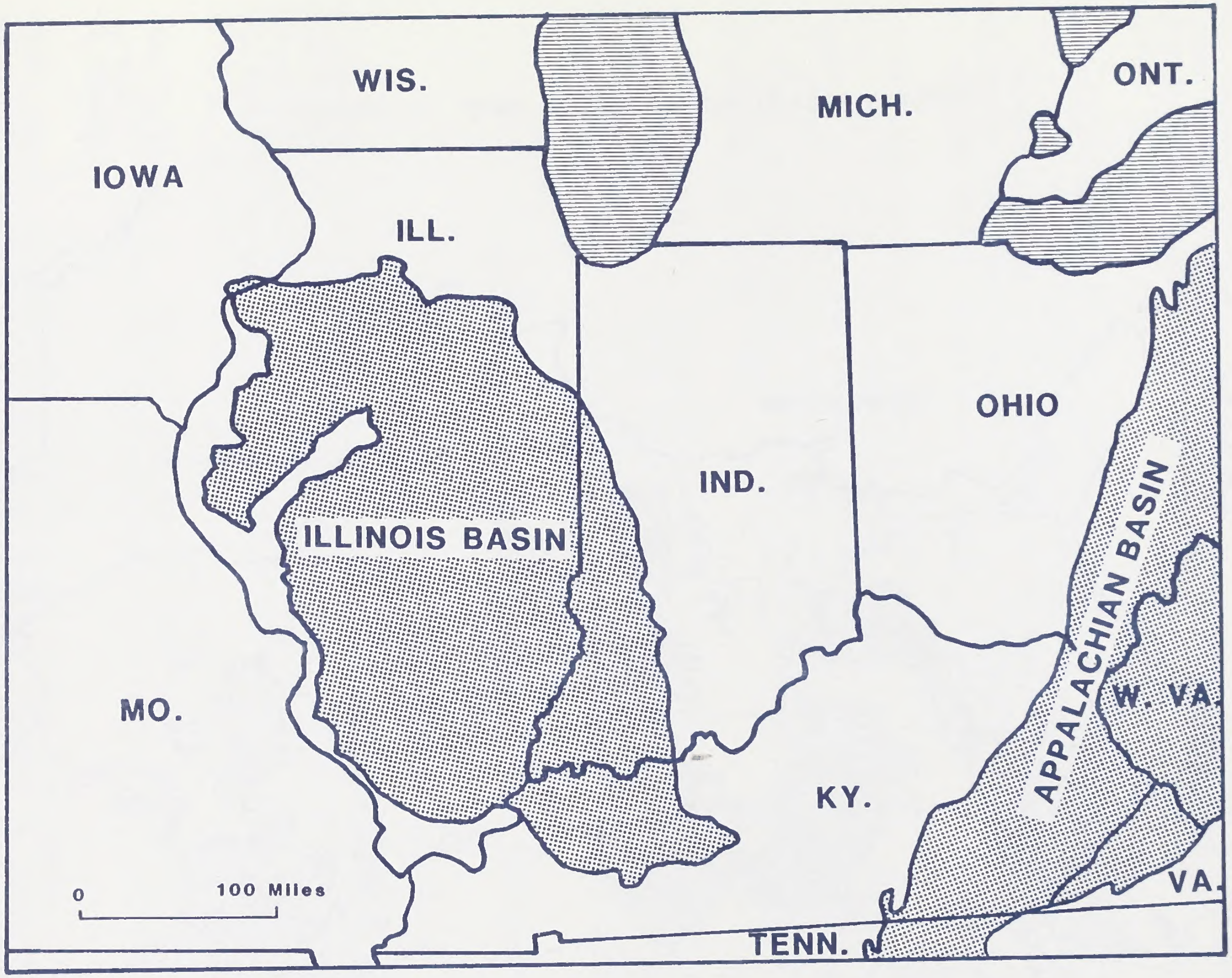


Figure 2. Illinois and Appalachian coal basins. Stippled pattern shows approximate area underlain by coalbeds. (Source: Surface Coal Mining and Reclamation in Indiana 1981).

Depth and Thickness of Coal Seams

The multiple coal deposits in the Illinois Basin are bowl-shaped, with the central position of the bowl being deep mined, and the outer edges of the bowl in portions of western Kentucky, southwestern Indiana, and southern Illinois being surface mined. The geology thus defines the location and availability of coal to be surface mined.

The coal seams themselves are generally 4 to 6 feet thick, with overburden material ranging from 60 to 130 feet. In southwestern Indiana the coal seams dip westward toward the center of the Illinois Basin at the rate of about 20 feet per mile (Carter et al. 1974).

The overburden itself contains a high proportion of shale. This shale, which normally lies directly above the coal, frequently contains a high percentage of pyritic sulfur which causes many problems in unreclaimed or improperly reclaimed mines.

Mining Technique and Coal Processing

While there are large resources of underground coal, the majority of the coal in this portion of the Interior Basin is surface mined. The equipment used is electrically operated draglines. Dragline buckets at most of the large mines are in the 100- to 125-cubic-yard capacity range. Many small mines are present in the region. These are diesel-powered or electrical draglines with bucket capacities as small as 7 cubic yards.

The type of mining done here is called area mining (Fig. 3). In area mining the overburden is removed in strips up to a mile long and about 100 feet wide. Blasting loosens the overburden, and topsoil and other overburden material are separated. The exposed coal is then removed with smaller shovels, end loaders, and bulldozers. Reclamation is accomplished by replacing the overburden and topsoil, regrading, and revegetating.

The high acid content of most of the surface mineable coal requires treatment prior to use. Most of the large mines have coal processing plants that prepare the coal by crushing the coal to size, removing undesirable waste rock materials, and finally washing the coal to remove as much of the pyrite sulfur as possible. The native sulfur is unaffected by this process.

In this way most of this coal becomes acceptable as power plant fuel. If after this process the coal still cannot be burned to meet EPA sulfur dioxide standards, it is mixed with lower sulfur coal in an attempt to meet the criteria.

POTENTIAL LIMITATIONS FOR FULL COAL DEVELOPMENT

Environmental Barriers

If any part of the U.S. possesses potential for land reclamation and

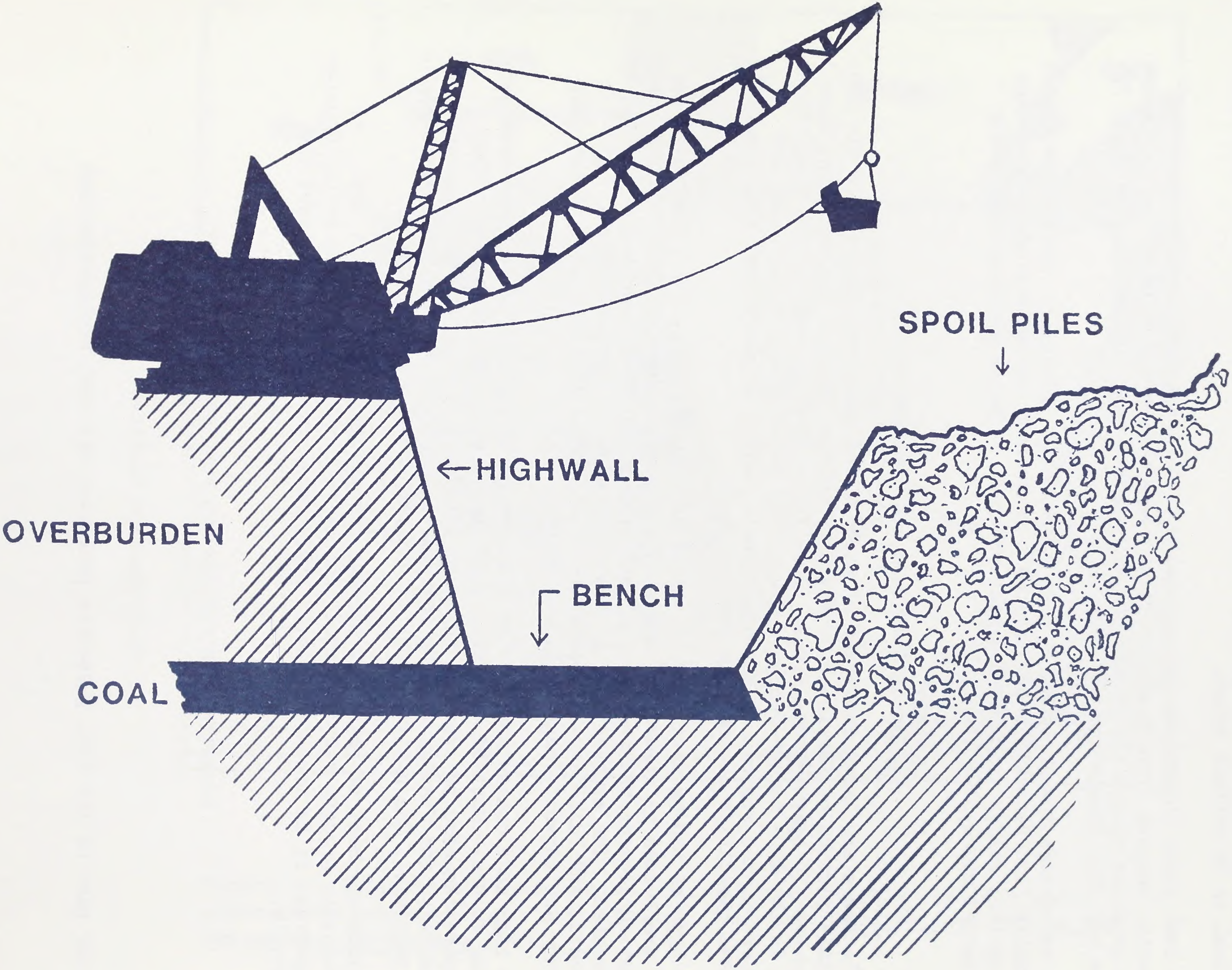


Figure 3. Area mining. (Source: *Coal Data: A Reference* 1980).

mitigation of environmental problems, it would be the Illinois Basin. This is not to say such standards are being or have been lived up to.

Most of the Illinois Basin has precipitation in the 40 to 50 inch range. This, coupled with a long growing season, produces an active biological area. The cold winters close the system down for only a few months each year.

The original topography is relatively flat. Proper mine reclamation planning can assure that runoff from the mine sites will be contained and other offsite damage minimized. Final cuts normally fill with water in this environment and can be restored to provide recreation potential to an area that doesn't have an abundance of natural recreation sites.

Reclamation Potential for Midwestern Coal

The above statements should not be taken to mean that such ideal reclamation is being done. They simply support the position that if reclamation is going to work anywhere, it should work in the eastern part of the Interior Coal Basin. Unfortunately, because the natural environment there is so conducive to reclamation, a casual attitude toward reclamation has evolved which may lull regulators and operators into a false sense of security in reclamation planning. For example, mine public relations personnel proudly claim 40 bushels of wheat an acre off reclaimed Indiana land. While this may sound impressive to urban dwellers, or people from more arid parts of the country, this is slightly more than half the expected yield for wheat from prime agricultural land in Indiana. As long as the acid-bearing material is not placed near the surface, and high rates of nitrogen fertilizer are applied, plant growth of some type can be established in a growing season. However, the goal here should not just be reclamation to a point where ground cover exists, but to a point where the environment can support the same level of agricultural productivity that took place in the pre-mine situation. When mining prime farmlands, we owe it to future generations to assure this criterion is met.

Table 3 illustrates the problem in Indiana. From 1968 to 1978 the number of mine permits more than quadrupled, and the number of acres mined nearly tripled. Mined lands were largely reclaimed to range or a pasture and hay system.

Motivation on the part of the mining companies was quite simple. Prior to passage of the Federal Surface Mining Control and Reclamation Act in 1977 (House of Representatives Committee on Interior and Insular Affairs 1977), Indiana law only required that areas reclaimed for range or pasture and hay be graded to a maximum slope of 25 percent and normally did not require topsoil replacement. This enabled the mining companies to spend less for earth moving than they would have had to for cropland (8% maximum grade). Then, the land could be passed to a subsidiary corporation--for example, AMAX Coal and its subsidiary, Meadowlark Farms. Cattle were turned out on the land after vegetation had begun to establish itself, and a relatively quick return on the investment was realized (Surface Coal Mining and Reclamation in Indiana 1981).

TABLE 3. SURFACE MINE PERMIT DATA

	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Number of Permits issued	41	36	38	42	42	47	66	107	128	179	181	192
Number of acres mined	3402	3617	4100	3930	4206	4597	4773	5377	5395	6058	9982	8139
						Percentages						
Land use data												
Forest	38	15	30	22	11	5	5	7	3	4	12	8
Range	60	83	64	59	68	60	38	28	33	13	0	0
Pasture and hay	1	1	5	17	8	12	24	31	35	45	44	44
Row Crop and others	1	1	1	2	13	23	33	34	29	38	44	48

Source: Surface Coal Mining and Reclamation in Indiana. 1981.

Returning the land to cropland status required much postmining investment. Returning land to forest created another situation. The reclaimed slope allowance was generous (up to 33 1/2%), but owning land and paying taxes on it for 50+ years while waiting for the trees to mature had little appeal to practical businessmen.

Between 1968 and 1977 (as Table 3 shows), as much as 84% (a minimum of 50%) of the mined land was reclaimed to pasture or range and hay. In 1978, range dropped to zero and pasture to 44% of the total acreage reclaimed. Cropland increased to an all-time high of 44% and forest to 12%. This probably stems from passage of the Federal Surface Mining and Reclamation Act, which requires that mined land be returned to approximate original use and contour or an approved higher or better use. These percentages seem more appropriate for an agricultural State such as Indiana and correlate more favorably with food chain requirements to feed a hungry world.

Illinois reflects a similar pattern from 1962 to 1971, when 90% of the surface-mined lands were reclaimed to forage. From 1971 to 1975, forage made up 56.5% of the reclaimed lands, and forage row crop capability 25.7% (Smith et al. 1978). Again, these are hardly land uses one would encourage on some of the most productive agricultural soil in the U.S., if not the world.

Table 4 shows the acreages mined by county in the southwestern coal fields of Indiana from 1941 to 1979. As with most parts of the United States prior to 1950, the majority of the coal was deep mined. Surface mining began in the 1920s and surface-mined coal produced nearly 15 million tons per year during World War II. After World War II, a decline in surface-mined coal lasted until the late 1950s and early 1960s.

However, total acreage of surface-mined land in Indiana has been increasing rapidly in recent years. The percentage of county land area mined to date in the coal-producing counties ranges from an insignificant 0.02% in Warren County to 18.58% in Warrick County.

EXTENT AND CHARACTER OF EASTERN COAL RESOURCES

Geographic Locations of Coal Deposits

Eastern or Appalachian coal is defined in Figure 2. This portion of the paper will concentrate primarily on central Appalachia, which comprises eastern Kentucky, southwestern Pennsylvania, and almost all of West Virginia.

The topography here is quite different from that of the Midwest. This hilly environment is the result of the intricate dissections of the old Cumberland and Allegheny Plateaus. It is characterized by steep, narrow valleys and relatively flat-topped mountains 500 to 800 feet above the valley floors.

Soil conditions are poor. The steep slopes lend themselves to erosion, and "A" horizons of only 2 to 3 inches are common. In spite of this, a large number of small farms dot the area. The native vegetation is deciduous hardwoods.

TABLE 4. MINED ACREAGE BY COUNTY AND YEAR

County	1941-67	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	Total Acres Mined	Total Acres in County	Percent of County Mined
Warrick	24,964	1,152	1,544	1,656	1,441	1,386	1,703	1,894	1,944	1,672	1,338	3,364	2,418	46,476	250,200	18.58
Pike	21,096	524	505	662	681	767	742	1,039	816	1,155	1,305	1,760	1,707	32,759	214,400	15.28
Clay	15,208	213	206	155	127	123	83	27	329	218	379	662	471	18,201	232,900	7.81
Greene	12,588	831	648	499	380	343	374	209	176	262	193	339	174	17,016	351,300	4.84
Sullivan	10,624	642	511	837	859	939	760	641	871	588	373	914	619	19,178	292,500	6.55
Vigo	7,834	--	--	40	30	50	280	224	213	180	96	242	445	9,634	265,600	3.63
Vermillion	2,560	5	151	208	306	448	245	240	348	229	342	557	161	5,800	168,300	3.45
Knox	2,561	--	--	--	32	--	199	179	87	176	141	344	274	3,993	330,900	1.21
Spencer	1,587	14	19	19	41	98	154	296	233	473	1,003	809	705	5,451	253,400	2.15
Owen	1,841	3	3	--	--	--	11	12	14	8	4	17	54	1,967	246,400	.80
Daviess	1,713	7	11	--	--	--	--	--	92	86	205	277	466	2,857	277,100	1.03
Gibson	937	--	--	--	--	40	36	--	64	71	235	85	173	1,641	319,300	.51
Fountain	652	1	2	6	8	5	6	5	16	6	39	63	66	875	254,100	.34
Parke	456	--	5	6	5	4	2	5	--	--	--	7	11	502	288,600	.17
Perry	320	--	--	---	7	--	--	--	35	89	94	41	0	586	245,700	.24
Dubois	81	--	--	--	--	--	--	--	80	157	282	334	371	1,305	277,120	.47
Martin	50	--	--	--	--	--	--	--	57	19	26	162	23	337	220,800	.15
Warren	34	--	--	--	--	--	--	--	--	--	--	1	1	36	235,520	.02

Source: Surface Coal Mining and Reclamation in Indiana 1981.

Depth and Thickness of Coal Deposits

Coal beds in Appalachia are the result of the repeated draining and filling of ancient swamps in the Appalachian geosyncline. When the geosyncline was uplifted some 250 million years ago, the coal seams were elevated to form the Cumberland and Allegheny Plateaus. Erosion has since created the narrow valleys and sent approximately half of the original coal into the Gulf of Mexico.

This has resulted in multiple coal seams high above the valley floor. The coal is bituminous in nature and has a great range in sulfur content. It is generally characterized as high sulfur, but beds of 1% sulfur coal do exist in the region. Much of this coal ranks as the highest quality metallurgical coal in the world. It is not uncommon for low-sulfur, high-grade bituminous coal to be taken here in seams as narrow as 12 inches.

Mining Technique and Coal Processing

Earlier in this century coal extraction was almost exclusively done using underground methods. Drift mines (Fig. 4) were dug into the horizontal coal beds above the valley floors. The coal was then removed in room and pillar fashion. The pillars were left to provide roof supports for the safety of the miners. However, this meant that as much as 35% of the total coal in the mine was left at the completion of the mining process.

Beginning in the 1950s, the surface mining of coal began in earnest in central Appalachia. Surface mining was perceived as a cheaper way to extract the resource. It no doubt was, since all the external costs of the mining were ignored by the companies doing the work. Also, surface mining requires fewer miners and can be put in operation more rapidly and with less capital.

The type of surface mining done here is contour mining (Fig. 5). In early mines, the overburden was pushed over the outslope, exposing the coal. The coal was then taken out of the mine site via a haul road cut into the slope. In this way mining proceeded around the mountain on the contour of the coal seam until an "island in the sky" remained above the mined-out coal bench. Modern reclamation techniques attempt to mitigate this disaster. They will be discussed in the following section.

The mining equipment used here is generally smaller than that used in midwestern mines. The benches cut in the mountain slopes are normally no more than 100 feet wide. Narrow haul roads and steep slopes all make small equipment more desirable here.

Currently there is great debate over the fate of this overburden material. With some exceptions, the Federal Surface Mining Control and Reclamation Act requires restoration to original contour and also requires having no spoil material cast over the outslope.

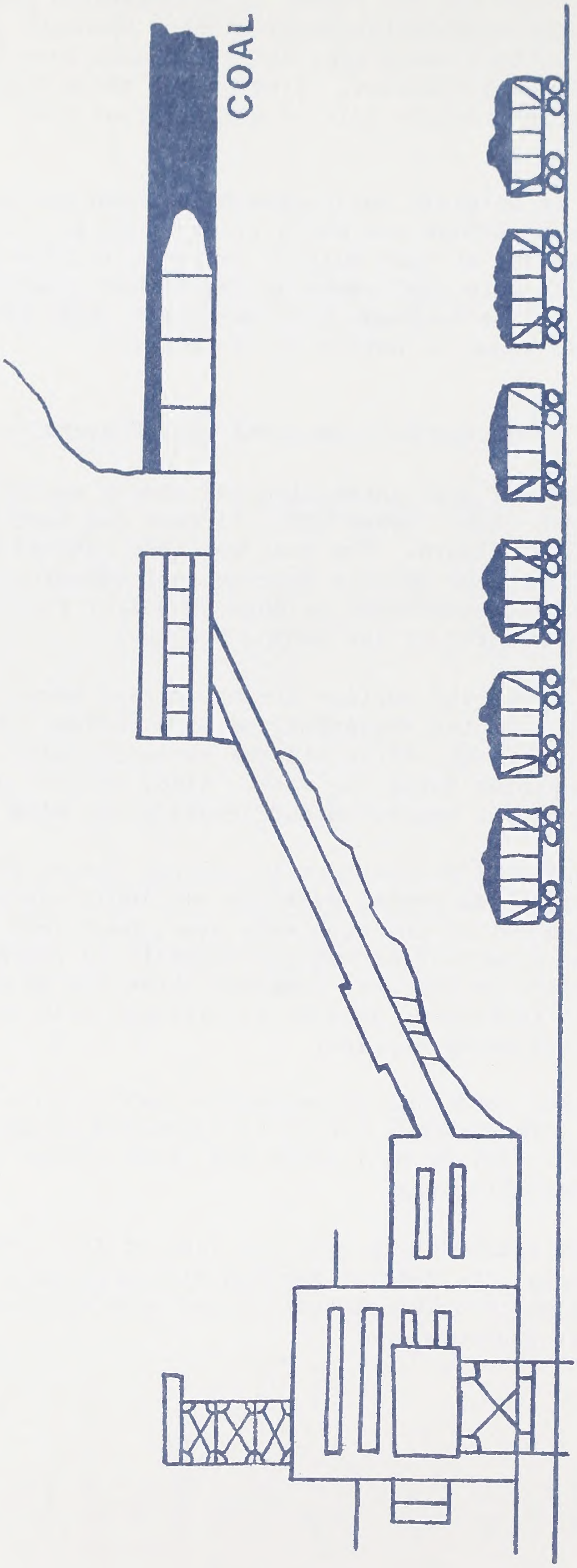


Figure 4. Drift mining.

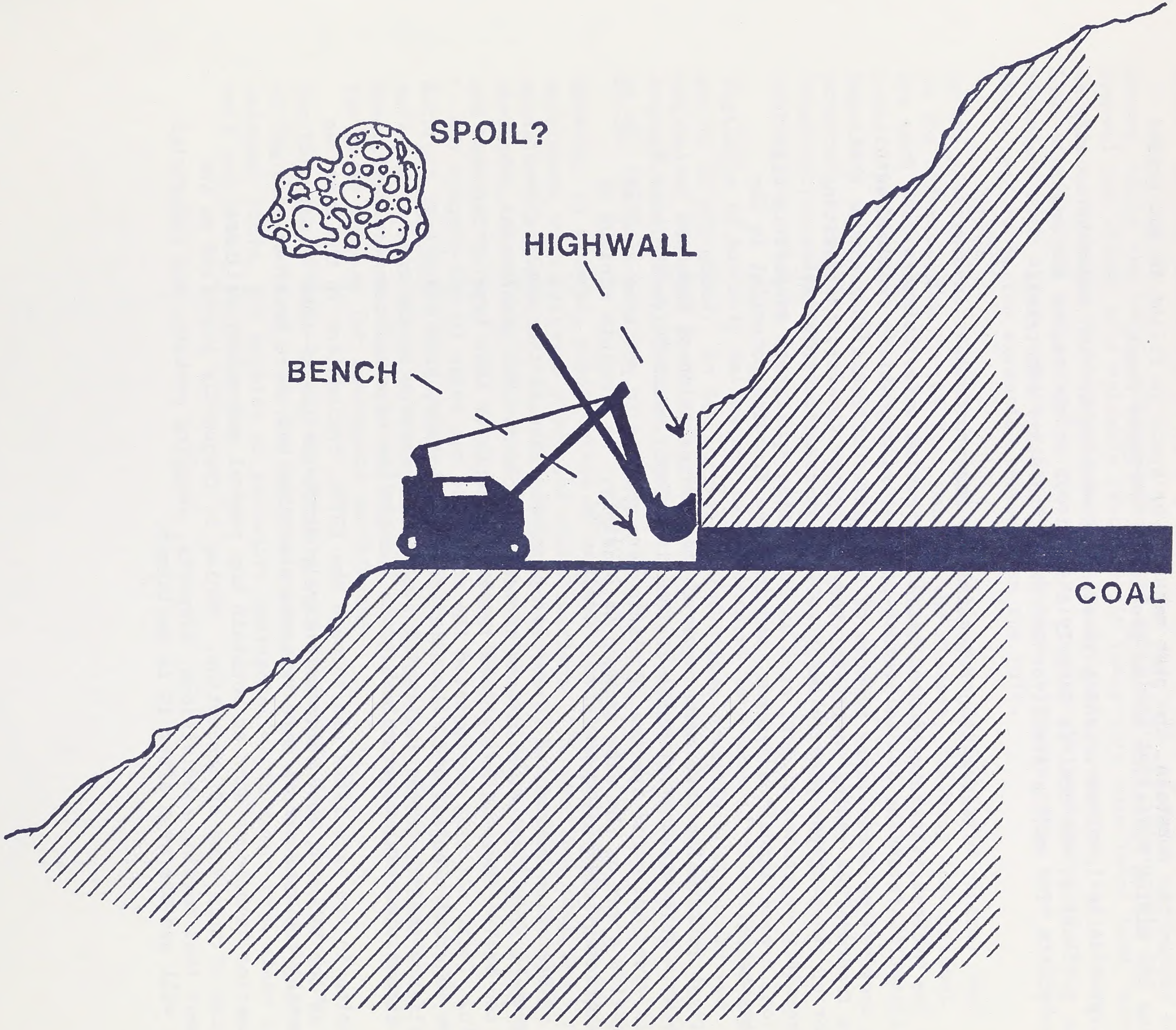


Figure 5. Contour mining. (Source: Coal Data: A Reference 1980).

Other techniques used here have involved mountain top removal. In this method the entire top of the mountain is taken off. Thus, no "island in the sky" results and, since the overburden is used to fill the valleys, large amounts of flat land are created above the valley floors.

Block cutting, or cut and fill, is also a recent and expensive mining technique employed in the area. In this type of mining, as the actual mining moves around the mountain, the cast material or spoil is filled in and graded behind the mining operation on the previously stripped bench.

Coal processing involves crushing to size and washing as with midwestern coal. After processing, the coal is largely shipped out of the region for use in power plants, for making steel, or for export to other countries.

Reclamation Potential for Eastern Coal

Like the Midwest, this environment has a very active water balance. Precipitation is in the 40- to 50-inch-per-year range, which, combined with long summers, produces large amounts of biomass. One would thus assume that scars from surface mining would heal very quickly. However, the limiting factor of steep slopes plays a major role in reclamation problems. Inadequately vegetated slopes, such as strip mine spoil, are subject to high erosion, create landslide hazards, and increase flooding potential in the valleys below.

The first reclamation laws here required only revegetation of the cast material. This was a period when reclamation simply meant "hide the scar." Exotic vines and other species of plants were planted to get some kind of vegetative cover on the site as soon as possible. An absolute minimum of reclamation grading was done.

This revegetation method led to further problems. The exotics would grow in areas where acid overburden did not present a problem. The problem was, they grew too well. Cudzu vine might be the best example of this type of imported exotic. Cudzu not only revegetated the mine site but began to out-compete the native vegetation adjacent to the site itself. Further, once cudzu had established itself, normal vegetation succession patterns on the mine site were impossible. The vegetation used to reclaim the mine had become a pest.

Beginning in the late 1960s and through the 1970s, reclamation in the East, as well as the Midwest, moved into an entirely different phase--that of actually converting the land into a more valuable site than was there prior to mining.

Reclamation techniques such as mountain top removal and valley fill are examples of this kind of perception. Mining is frequently justified on the argument that housing subdivisions, airports, shopping centers, and industrial parks will use the area after it is reclaimed.

Some questions seem in order here. First, as reclamation techniques moved forward under the "improved land use" scheme, wildlife and natural vegetation were not better off, but worse off. This point is little understood by environmental groups that have lobbied for the past 20 years for improved reclamation lands. In fact, the case could be made that as reclamation laws have improved through the years, wildlife conditions have actually gotten worse.

Second, while the level, non-prone-to-flood reclaimed land in mountain top removal may indeed be a valuable resource, it takes more than level land, even in this environment, to bring in housing subdivisions, industry, and airports. Laws of geography and economics come into play with the remoteness of the reclaimed mine sites. While a few subdivisions, airports, etc. have evolved, these tend to be the exception rather than the rule.

In the eastern coal region off-site damage is more difficult to control than in the Midwest. Due to the flat land in the Midwest, drainage and sediment are much easier to control. Relatively simple techniques can be used to contain problems at the mine site itself. In Appalachia, problems are magnified. Unfortunately, the techniques to control the problem have not advanced as rapidly as mining technology has. Sediment traps, terracing, interception and diversion, and storage remain as the major methods of controlling off-site damage.

Vigilance in not only design but in maintenance is a must if off-site damages are to be minimized. An EPA survey concluded that properly constructed and maintained sediment ponds can efficiently remove suspended solids under average conditions. However, during storms, efficiency is decreased (Kathuria et al. 1976).

However, in general, construction of sediment ponds was not found to be in accordance with approved plans and specifications. In addition, once the ponds were constructed, they were found to be poorly maintained. The EPA concluded that timely removal of all accumulated sediments, spillway cleaning, and embankment repair was vital for a proper functioning sediment system.

Kathruia et al. (1976) concluded that "Approximately one-half of the ponds surveyed did not meet the State or Federal effluent standards during the measured baseline and storm conditions." Poor design and maintenance were the two major reasons for inadequate performance.

Further, ponds built in stream channels were frequently left in place after mining was completed. As dam failures occur over time in the poorly designed sediment ponds, the problem of excessive sedimentation on downstream areas is only postponed, not reduced.

POTENTIAL LIMITATIONS FOR FULL COAL DEVELOPMENT

Environmental Barriers

Whether or not the aforementioned environmental problems in the midwestern and eastern coal fields are limiting enough to interfere with full coal development should be a matter for public debate. Most studies on coal identify these problems and then either ignore them or make the assumption that environmental damages can be mitigated through better science, technology, or engineering. Unfortunately, most of these latter arguments are based on faith rather than on appropriate solutions. Nonetheless, additional problems are in the offing which affect both midwestern and eastern coal.

1. Acid Rain.--A growing awareness of acid precipitation caused from the burning of coal in midwestern and eastern power plants has come to the fore in the past few years. Computer models have demonstrated the probability of fish kills in lakes in New York State and Canada being the result of coal burning in the area covered in this paper.

   Until recently, research seemed to be aimed at removing the acid rain-causing gases from the smokestacks of power plants after the coal was burned. This type of removal results in large amounts of captured sludge which must be disposed of, thus creating another problem.

   Before sulfur dioxide controls were placed on power plants, they could convert about 40% of the coal's chemical energy to electricity, the remainder of the energy being dumped into the environment as waste heat. The power demands of sulfur dioxide scrubbers require that new plants will operate at efficiencies of only 38%. In addition, EPA-proposed regulations could add over $150 Kwe to the capital costs of large plants, which would cost $550 Kwe (1976 dollars) without such measures. This 15 to 20% increase in cost makes electrical utilities very receptive to other ideas regarding sulfur removal (Energy in Transition 1985-2010 1980).

   One of the alternatives currently under investigtion is to remove the sulfur from the coal before it is burned. Coal washing referred to earlier in this paper is the simplest and cheapest way to do this, providing the sulfur emission standards can be reached in this way.

   A third way to meet EPA sulfur regulations is to transport and burn western coal. Public utilities in the East already own lease rights to much western coal. If the technology to desulfur coal does not work, western coal is obviously the answer seen by many eastern utilities.

   An additional problem occurs here. It is estimated that nitrogen dioxide makes up 30 to 40% of the acid-causing gases from power plant stacks. Removing sulfur from coal as it is burned, before it is burned, or using low-sulfur coal does not in any way reduce nitrogen dioxide emissions. So, while dealing directly with sulfur helps cope with one part of the problem, it ignores another important aspect.

2. Acid Runoff.--Acid runoff from mine sites has been a recurring problem in both the Midwest and East, although it has been much more severe in the East. A report by the Appalachian Regional Commission (Acid Mine Drainage in Appalachia 1969) indicates that of the more than 10,500 miles of streams polluted by mine drainage, 5,700 miles were categorized as seriously polluted.

   It would be incorrect to attribute all of this stream destruction to surface mining. Prior to 1950, parts of Appalachia were heavily mined for coal using underground techniques. Most of the total acid pollution occurs as the result of these underground mines.

   Surface mining does contribute a substantial portion of the acid mine drainage, both from active and inactive sites. Attempts to control this problem must occur in both the post-mining reclamation and during the mining operation.

   The acid runoff from surface mining is formed when pyritic material is exposed to air and water. The iron and pyritics oxidize to form a weak sulfuric acid solution. As this acid passes over various rock material as it moves off the mine site, the acid dissolves metals such as iron, aluminum, and manganese. The surface mining of coal almost always exposes large quantitites of acid-producing materials to water and oxygen. The result is significant acid mine drainage unless the runoff can be contained or controlled in some other fashion.

   When an acid stream contracts a relatively clean stream, the acid is partly neutralized, iron precipitates out, and "yellow boy" coats the streambed of the previously unpolluted stream.

   Water quality deteriorates in other ways. Water hardness is increased as calcium, magnesium, and iron salts in solution create hard water. Conductivity, which increases in mined areas, is another measure of the amount of dissolved solids in the water and thus a measure of pollution.

   Building and chemically treating sediment ponds and controlling runoff seem to be the most promising ways to cope with this very complex problem. Figure 6 shows a schematic drawing of an EPA neutralization facility. Neutralization, ferrous iron oxidation, and sedimentation are the features of this idealized facility. Whether small mines have the capital, knowledge, or will to build such a facility is an important question.

   Holding the water in a sediment pond will allow suspended solids to settle out. Removal of the iron and other minerals which can be precipitated out requires chemical treatment of the runoff water.

3. Flooding.--There seems little doubt that lands stripped of vegetation have an increase in runoff after storms. In addition to increased runoff, reduced channel-carrying capacity due to siltation also occurs, which increases the probability of flooding.

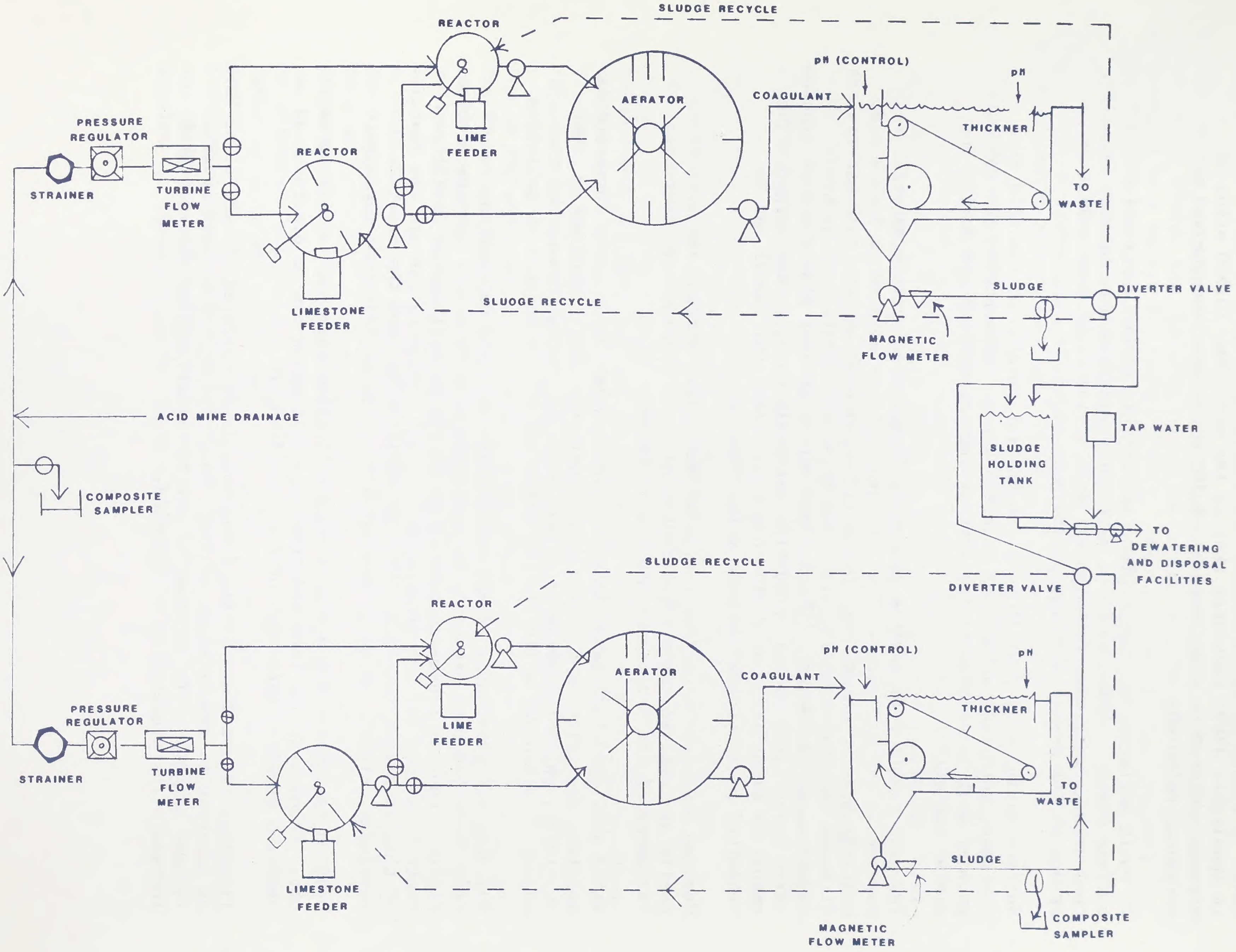


Figure 6. Schematic flow diagram for the EPA neutralization facility.

With the vegetation canopy removed, the amount of water intercepted is reduced. In areas where a high degree of shale is present in the overburden, surface sealing can occur. This also increases the likelihood of rapid runoff (Dyer and Curtis 1977).

As larger numbers of watersheds are mined, flood potential in the area will tend to increase over a wider portion of the countryside. Sediment ponds and other catchment basins seem to be the only method for containing as much water as possible close to the mine site where it can then be released more slowly to lower the peak water flow in the stream. The previously quoted EPA study on sediment ponds would seem to indicate major work needs to be done in the entire area of sediment basin design, construction, and maintenance.

Runoff reduction in both amount and velocity are necessary. By manipulating slope length and grade, the flow, velocity, and rate can be reduced. Soil alteration can increase the infiltration rate and also slow runoff. Mulching and revegetation also aid in runoff reduction.

4. Soil Erosion and Siltation.--There are three major sources of sediment recognized in conjunction with surface mining. These are spoil, haul roads, and the mine area itself (Down and Stocks 1977). Large amounts of spoil can move down slopes, damaging adjacent land and often closing or blocking stream channels. Roads are put in as cheaply as possible, often without good design and adequate drainage. These roads are abandoned after the mine is closed and deteriorate to become an important source of sediment. The strip mine area itself is also an important source of sediment. Curtis (1972) measured a rate of 5.9 tons per acre per year from a mine site at Beaver Creek, Kentucky. This can be compared with 0.7 tons per acre per year from an unmined watershed (Dyer and Curtis 1977).

   Soil stabilization in humid areas can be accomplished through a variety of revegetative, chemical, and structural techniques.

   Proper revegetation is the most beneficial and permanent soil stabilizer. It shields soil particles from the direct impact of falling rain, while plant roots bind and hold the soil particles. It also slows runoff, thereby allowing the soil to absorb more water.

   Structural measures are used when revegetation alone cannot control soil erosion and siltation. Stone riprap is perhaps the most common material used to stabilize ditches and other man-made drainageways. Revetments are used to shield stream channels from the abrasive action of water flow. Check dams are also used to prevent stream channel erosion.

5. Chemical Pollution.--The studies done of the Breathitt, Kentucky, area by the Northeastern Forest Experiment Station at Berea, Kentucky, have become classics in dealing with water problems in surface-mined watersheds in the eastern United States. As part of their ongoing research, U.S. Forest Service Researchers conducted a 4-year study of the chemical quality of water in six small watersheds. This study showed that chemical pollution in mined watersheds occurs even if there is no acid problem (Table 5).

TABLE 5. MAXIMUM CONCENTRATIONS OF CHEMICAL ELEMENTS IN STREAMS

Watershed	Specific Conductance	pH	Parts per million								
			Fe	Al	Mn	SO_4	Ca	Mg	Zn	Cu	Alk
Before Surface Mining											
LW A	55	7.3	0.38	0.07	0.08	12	4.8	3.6	0.90	0	18
B	55	7.1	0.31	0.07	0.00	18	4.5	2.4	0.10	0	10
C[1]	--	--	--	--	--	--	--	--	--	--	--
Jenny	151	7.7	0.60	0.19	0.10	84	20.0	7.0	1.20	0	80
Miller	73	7.0	0.27	0.05	0.12	12	6.2	4.4	0.80	0	24
Mullins	95	7.0	1.38	0.06	0.30	10	6.6	3.8	0.90	0	30
USPHS[2]	--	--	0.30	--	0.05	250	--	--	5.00	1.00	--
After Surface Mining											
LW A	407	7.8	4.00	0.44	1.85	178	45.0	35.5	1.80	0	80
B	522	8.1	1.55	0.25	1.80	176	50.4	36.0	2.20	0	90
C	670	7.8	5.26	0.19	0.10	300	95.0	23.0	2.10	0	54
Jenny[3]	--	--	--	--	--	--	--	--	--	--	--
Miller	334	7.5	3.80	0.15	1.20	132	30.0	24.3	1.20	0	58
Mullins	264	7.5	3.50	0.19	0.70	61	18.3	17.6	1.26	0	80

[1] No data prior to mining.
[2] Maximum allowable standard which watersheds were measured against.
[3] No mining in watershed.

Source: Curtis 1972.

The elements showing the greatest increases after mining were sulfate, calcium, and magnesium, although aluminum manganese, iron, and zinc also increased (Curtis 1972).

6. Accessibility of Coal, Surface and Underground Mining.--Table 6 depicts the reserve base of coal by State. Of the more than 4 trillion tons available, approximately one-third has been classed as surface mineable coal. The top 10 States are 1) Montana, 2) Wyoming, 3) Illinois, 4) Texas, 5) North Dakota, 6) Kentucky, 7) Ohio, 8) West Virginia, 9) Colorado, and 10) Alabama.

   Of these 10 states, those west of the Mississippi contain nearly two-thirds of the total strippable tonnage (107,993.5 million short tons), while those east of the Mississippi contain only 37,433.6 million short tons. It would be misleading to associate strippable tonnage with strippable acreage. The deep seams in the West will require fewer acres per ton to be disturbed, but since the Btu value of western coal is less than that of midwestern and Appalachian coal, more tons will have to be mined to produce the same electrical output.

   Table 7 illustrates this problem. The strippable western coal reserves are almost exclusively subbituminous and lignite, while surface mineable eastern coal is largely bituminous.

   Eastern and midwestern coal is near the domestic markets, can be converted to coke for use by relatively close steel mills, and is nearer the East Coast port cities which tie it to world coal markets.

   Western coal has none of these advantages. Its major strength lies in its low sulfur content and ease of mining. It has been almost exclusively used for electric power production and has potential heavy use if coal gasification becomes widespread.

Social and Political Constraints

Midwest

Historically, this area has been viewed as a farming region based on cash grain and livestock farming. Corn and soybeans are the major crops. The soils by and large are extremely productive. Many counties average 120 bushels of corn per acre.

Agricultural surpluses have long been a feature of this area. Its low-intensity land use is exemplified by the large number of small farms present. This land is under pressure not only from mining interests but from urban development as well. As our population grows, and as American agricultural exports are viewed as a trade item which must be used to pay for imported oil, conversion of large amounts of this land from agriculture to mining should be a matter for public decisionmaking.

Can reclamation restore this land to its past production levels after mining? This question must be answered in the context of all components of the system.

TABLE 6. DEMONSTRATED RESERVE BASE OF COAL IN THE UNITED STATES BY POTENTIAL METHOD OF MINING[1]

State	Underground	Surface	Total
Alabama	3,699.7	3,060.1	6,759.8
Alaska	5,423.0	732.5	6,155.5
Arizona	101.6	322.7	424.3
Arkansas	272.5	138.5	411.0
Colorado	12,439.6	3,775.2	16,214.7
Georgia	1.9	1.8	3.7
Idaho	4.4	--	4.4
Illinois	52,957.6	14,747.4	67,705.0
Indiana	8,938.9	1,682.2	10,621.1
Iowa	1,734.3	464.3	2,198.6
Kansas	--	994.8	994.8
Kentucky, East	8,831.6	4,266.7	13,098.2
Kentucky, West	17,033.3	4,108.6	21,141.9
Maryland	714.1	112.1	826.2
Michigan	123.1	4.6	127.7
Missouri	1,479.1	4,598.1	6,077.2
Montana	70,958.7	49,510.1	120,468.8
New Mexico	2,145.9	2,395.6	4,541.5
North Carolina	10.7	--	10.7
North Dakota	--	9,971.2	9,971.2
Ohio	13,005.1	6,029.5	19,034.7
Oklahoma	1,238.4	405.6	1,644.0
Oregon	14.5	2.9	17.5
Pennsylvania	29,070.4	1,357.5	30,427.9
South Dakota	--	366.1	366.1
Tennessee	664.7	333.0	997.7
Texas	--	12,693.5	12,693.5
Utah	6,233.7	267.9	6,501.6
Virginia	2,680.0	858.0	3,537.9
Washington	1,090.7	489.5	1,580.2
West Virginia	34,763.6	5,221.3	39,984.9
Wyoming	42,568.6	27,445.4	70,014.0
Total	318,199.7	156,356.6	474,556.2[2]

[1] As of January 1, 1979; figures in million short tons.

[2] Data may not add to totals shown due to rounding.

Source: Demonstrated Reserve Base of Coal in the United States on January 1, 1979. 1981.

TABLE 7. DEMONSTRATED RESERVE BASE[1] OF COAL IN THE UNITED STATES BY AREA, RANK AND POTENTIAL METHOD OF MINING[2]

Area/Method of Mining	Anthracite	Bituminous	Subbituminous	Lignite	Total[3]
East of Mississippi River					
Underground Minable	7,088.6	165,406.1	--	--	172,494.7
Surface Minable	132.6	40,567.0	--	1,830.0	41,782.7
Total	7,221.2	205,973.1	--	1,083.0	214,277.3
West of Mississippi River					
Underground Minable	116.4	26,835.4	118,753.2	--	145,705.0
Surface Minable	7.8	9,066.4	63,689.8	41,809.9	114,573.9
Total	124.2	35,901.8	182,443.0	41,809.9	260,278.9
Total (east and west of Mississippi River)	7,345.4	241,874.9	182,443.0	42,892.9	474,556.2

[1] Includes those parts of measured and indicated resource categories as defined by Energy Information Administration and represents 100 percent of coal in place.

[2] As of January 1, 1979; figures in million short tons.

[3] Data may not add to totals shown due to rounding.

Source: Demonstrated Reserve Base of Coal in the United States on January 1, 1979. 1981.

High rates of fertilizer application can give the appearance of restoring the land to agricultural uses. If the application rates are higher than in the premining case, or if we convert land from crop to beef production, we have moved higher on the energy food chain and the production efficiency of the system has decreased.

A U.S. Department of Agriculture study has concluded that on a national scale, relatively little farmland will be disturbed by increased coal mining (McMartin *et al*. 1981). However, on a regional scale, the largest losses will occur in the Interior Coal Basin. Agricultural losses here were estimated to be $10 million annually because of increased mining.

Although more acreage would be disturbed in the eastern coal areas, the value of this land for agriculture is lower. The USDA study projected a $4 million per year loss in agricultural activity in this region due to future coal mining.

One of the major conclusions of the National Coal Policy Project (Murray 1978) was the recognition that Illinois Basin coal coincides with some of the most agriculturally productive land in the world. Utilization of coal resources in this region must not impair the long-term agricultural productivity of the land (Murray 1978):

> The basic goal of surface mine reclamation in the Midwest should be to return mined land to its previous, or higher potential for agricultural use. Where this reclamation is accomplished, the aggregate productivity index (or other measure of productivity) should be restored to premining levels. . . To accomplish this goal: 1) segregation and replacement of topsoil, preferably without stockpiling, should be a basic requirement of all surface mine reclamation, unless other material is demonstrated to be more suitable; 2) as much as possible of the disturbed areas should be graded to the same or gentler slopes than existed prior to mining.

Appalachia

The eastern coal fields have historically been viewed as generally poor farming areas. Urban development on a large scale has taken place only on the outer edges of the Appalachians, and the natural resource wealth of the region has been largely exported to the benefit of urban dwellers in the East and Midwest (*Reclamation Practices and Environmental Problems of Surface Mining* 1977).

Mechanization of underground mines and the trend toward surface mining in the 1950s gave rise to a large body of unemployed people. During the 1950s and early 1960s, high out-migration to the surrounding urban areas characterized much of Appalachia. Older people and young children were left behind, creating the welfare, poverty region witnessed by John Kennedy in the 1960 presidential election.

While conditions today in the Appalachians are certainly better than they were in the poverty period of the 1950s and 1960s, the past patterns hold well enough. Land ownership in the coal-producing counties is controlled by the mining companies or timber corporations (Noyes 1978).

ABANDONED MINE LANDS: THE LEGACY OF SURFACE MINING

Cries from the surface mining industry are frequently heard concerning regulation and/or overregulation of their industry. While no one desires to interfere in the competitive market with an overabundance of red tape and bureaucratic meddling, a case can be made for regulation of surface mining by society. A look at the record will quickly show the abuses caused by a nonregulated industry.

Abandoned Mine Lands (AML's) are lands that have been mined in the past and for any number of reasons have either not been reclaimed or reclamation efforts have failed. When the Surface Mining Control and Reclamation Act of 1977 was passed, Title IV of the Act established a system to deal with these past abuses. A tax of 35 cents per ton on current coal produced by surface mining and 15 cents per ton on underground mining was established by law. This created a pool of money to be used to reclaim AML's.

Table 8 indicates the amount of money collected in this fund as of February 1982 in Illinois, Indiana, and Ohio. This money will be made available by the Federal Office of Surface Mining to States upon approval of their AML inventories and reclamation plans. The AML Survey in Illinois has identified over 200,000 acres of land affected by mining (all mining, not just surface). Almost 23,000 acres of this has been classed as eligible for AML funds in a priority class. These acres (10% of all lands affected by Illinois coal mining) were classed as follows:

1.	Exposed refuse material	5,034 acres of gob 3,991 acres of slurry
2.	Tipple sites	854 acres
3.	Toxic and/or sparsely populated spoil banks	10,803 acres
4.	Adversely affected water acres	1,135 acres
5.	Adjacent disturbed areas	858 acres
6.	Abandoned deep mines - 70 with potential hazardous or polluted mine entries (Nawrot *et al.* 1980)	

Indiana has identified approximately 150,000 acres of land affected by surface mining, with additional acres affected by deep mining. Of this, 9,142 acres have been classed as derelict land (AML), in addition to 974.5 acres of lakes plus unknown miles of streams (*Indiana State Reclamation Plan* 1982).

TABLE 8. OFFICE OF SURFACE MINING
REGION III
FEE COLLECTION

Quarter Ended	Illinois	Indiana	Ohio	Total
FY 78 Total*	$10,520,567.33	$ 7,390,877.20	$11,009,159.18	$ 28,920,603.71
FY 79 Total*	14,730,281.79	9,264,945.34	12,159,214.56	36,154,441.69
FY 80 Total*	14,967,748.25	10,292,956.37	11,006,703.75	36,267,408.37
31 Dec 80	3,464,617.91	2,607,922.32	2,758,174.57	8,830,714.80
31 Mar 81	3,917,755.87	2,718,594.05	2,919,567.17	9,555,917.09
30 Jun 81	713,682.55	1,172,309.80	1,219,704.89	3,105,697.24
30 Sept 81	3,878,346.21	2,833,707.67	2,957,258.45	9,669,312.33
FY 81 Total*	$11,974,402.54	$ 9,332,533.84	$ 9,854,705.08	$ 31,161,641.46
31 Dec. 81	$ 3,973,928.22	$ 2,861,772.35	$ 3,019,120.72	$ 9,854,821.29
Total Fee Collection as of 2/24/82	$56,166,928.13	$39,143,085.10	$47,048,903.29	$142,358,916.52

*FY monies actually available for allocation to States based upon reclamation fees paid and deposited between October 1 and September 30 of fiscal year, even though payment may refer to prior period. Amounts per this report may differ from amounts reported in Federal Registers.

Source: Fee Collection Data 1982.

Indiana had prioritized 110 AML's (2,306 acres) as extreme danger sites. The first 31 of these are eligible under the initial grant cycle for AML funds. Cost estimates for their restoration total over $17 million. The top 40 priority sites will cost in excess of $36.5 million to reclaim.

Ohio has 450,000 acres of abandoned surface mines. It has been calculated that 120,000 acres are in need of "major" reclamation and 90,000 acres are in need of "moderate" reclamation. The remaining 240,000 acres have been subject to reclamation attempts resulting in acceptable vegetative cover and water quality. In addition to the acreage affected by surface mining, 7,000 acres of refuse pits exist, consisting of coal-processing waste.

More than 2,500 miles of Ohio's streams have been contaminated with coal-related pollution. Of this amount, over 1,000 miles are acidic, and in excess of 500 miles are affected by suspended sediment and sedimentation. Also, 2,700 acres of water in public water in public lakes and reservoirs have been degraded beyond the point allowble for their intended use (Ohio Plan Implementation Report: Abandoned Mined Lands 1982).

In Ohio during 1980, it cost $7,000 per acre to reclaim average active strip mines, $10,000 per stream mile to reclaim sedimentation-affected streams, $100,000 to $400,000 per site for landslide stabilization, and $10,000 to $45,000 per site for closure of mine openings. The cost of reclamation of all of Ohio's abandoned underground and surface mines has been estimated, in 1980 dollars, to be approximately $3.5 billion.

These States were selected for AML comments because, as indicated earlier, the Midwest possesses possibly the best potential reclamation environment in the country. If AML work here costs in the billions of dollars, the costs of inadequate reclamation in the hilly Appalachians or arid West will be astronomical. The AML legacy demonstrates that proper selection of mineable coal and proper reclamation planning are a must in the development of the nation's coal resources.

CONCLUSIONS

Development of U.S. coal resources is a complex, controversial issue, filled with dichotomies. A few are:

1. Midwestern and eastern coal vs. western coal
2. Air vs. water
3. Snowbelt vs. sunbelt
4. Prime farmlands vs. steep slopes vs. arid environments
5. State vs. Federal regulation
6. Free market vs. command market

7. Reclamation vs. sacrifice lands
8. Local desires vs. national needs

How the country chooses to deal with the coal issues will revolve around the trade-offs between these dichotomies. These choices are likely to be based more on political and economic grounds than on scientific or technical ones.

Advantages of eastern and midwestern coal lie in their proximity to markets, both domestic and export. The bituminous coal there can be used in the steel industry when converted to coke, and it has a higher Btu content than the western lignites.

The disadvantages of eastern and midwestern coal lie in the high sulfur content in much of the coal and, in the case of eastern coal, difficulties in reclamation.

The advantages for western coal lie almost exclusively with low sulfur content and ease of mining. Its major disadvantages lie in reclamation problems in a semiarid environment and distance from markets.

It may be too easy for the major population centers in the East and Midwest as well as on the West Coast and Gulf Coast to view the sacrifice of land in the West as necessary to maintain our energy-consumptive lifestyle. Possibly the key question in western coal development revolves around the issue of rights of the relatively small number of westerners to control a vast resource desired by a larger population base in another part of the country. How this point is resolved will determine the fate of western coal.

The fact that western coal lies largely on Federal land may prove to be the most important variable. The Federal government, through the Bureau of Land Management, has the power to lease high acreages of western coal. Eastern and midwestern coal is still largely in the hands of small landowners, although coal and timber companies do control significant acreages in some places. Thus, it will be more difficult to accumulate large acreages quickly to increase coal production in any significant way in the East and Midwest.

Developers of western coal should look to the history of the East and Midwest to gain perspective. The AML work demonstrates that the record of coal companies is far from outstanding. In fact, until the passage of tougher State reclamation laws in the late 1960s and early 1970s, the record could be viewed as dismal.

Under the Surface Mining Control and Reclamation Act of 1977, reclamation has improved even further, but questions remain regarding prime farmland productivity, and reclamation in mountainous environments. Current efforts are underway to rewrite Federal regulations, apparently to weaken rather than strengthen provisions relative to these questions.

It is with this background that citizens of the West must view development of their coal resource base. The question of coal development will touch them all. Hopefully, wise decision-making practices will guide their hands.

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AN OVERVIEW OF COAL LEASING, MINE DEVELOPMENT, AND FUTURE PRODUCTION IN THE POWDER RIVER COAL BASIN, MONTANA AND WYOMING

by

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INTRODUCTION

The Powder River Coal Basin is the most significant coal region in the Western United States. In 1980, 94 million tons of subbituminous coal was produced from this area of southeastern Montana and northeastern Wyoming (Fig. 1). More than half of this coal was Federally owned, and it accounted for about 50 percent of all Federal coal produced in the United States. Evaluations of existing and proposed mines in the Basin indicate that about 90% of the total production will be from Federally owned coal by 1986 (Office of Technology Assessment 1981). Thus, management of Federal coal exerts a major impact on the availability of reserves in this highly productive coal region.

This paper examines the nature of the reserve base at existing and proposed mines in the Basin, reports the ownership of Federal coal leases, outlines the proposals for developing production capacity at these mines, compares the expectations for production with various estimates of market demand for Powder River Basin coal, and evaluates some of the implications that demand/production relationships pose for coal leasing management.

GEOGRAPHY OF FEDERAL LEASES

Federal coal leases in the Powder River Coal Basin are concentrated around Colstrip and Decker, Montana, and in a 75- by 6-mile area extending north and south from Gillette, Wyoming. Scattered leases are also found in Sheridan, Johnson, and Converse counties, Wyoming. Federal leases in the Powder River Coal Basin collectively encompass about 160,000 acres; they contain an estimated recoverable reserve base of over 9 billion tons (Office of Technology Assessment 1981). All of the coal is subbituminous in rank.

The most significant area of existing Federal leaseblocks is the Gillette, Wyoming, area. Leases extend in an arc, approximately 75 miles from the Wildcat leaseblock, about 7 1/2 miles northwest of Gillette, to the proposed Antelope Mine, about 56 1/2 miles south-southeast of Gillette (Fig. 2). No leaseblock in this belt is more than 6 miles in width (measured east/west), and most are about 3 miles in width. These leases are all located along the eastern side of the Powder River Coal Basin, an area where target coal seams dip gently westward at less than 3°. Leases generally begin near the eastern outcrop of the target seams and extend westward as the seam or seams get deeper (Fig. 3). Usually, the economic limits of mining are found beyond the boundaries of existing leaseblocks, and all coal up to the lease boundary is recovered.

The target coal seam of all the leases in the Gillette area is the Wyodak. At its thickest, around Gillette, the seam ranges from 65 to 100 feet in thickness and sometimes has a thin parting a few feet thick within it. The Buckskin, Rawhide, Eagle Butte, Wyodak, Caballo, Belle Ayr, and Caballo Rojo mines all develop this essentially single thick seam. At the Wildcat leaseblock, north of the Buckskin Mine, the Wyodak splits into several seams, a

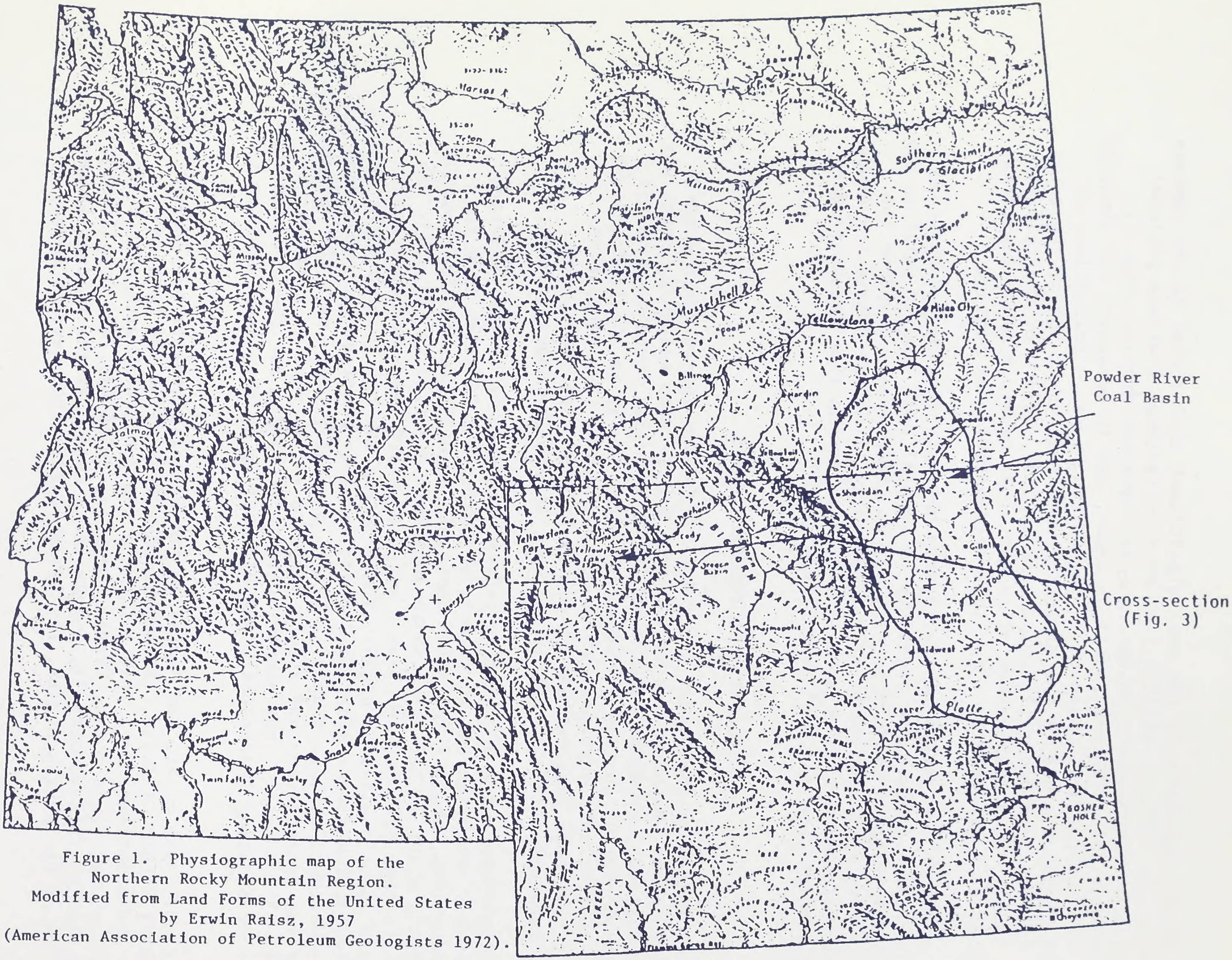

Figure 1. Physiographic map of the
Northern Rocky Mountain Region.
Modified from Land Forms of the United States
by Erwin Raisz, 1957
(American Association of Petroleum Geologists 1972).

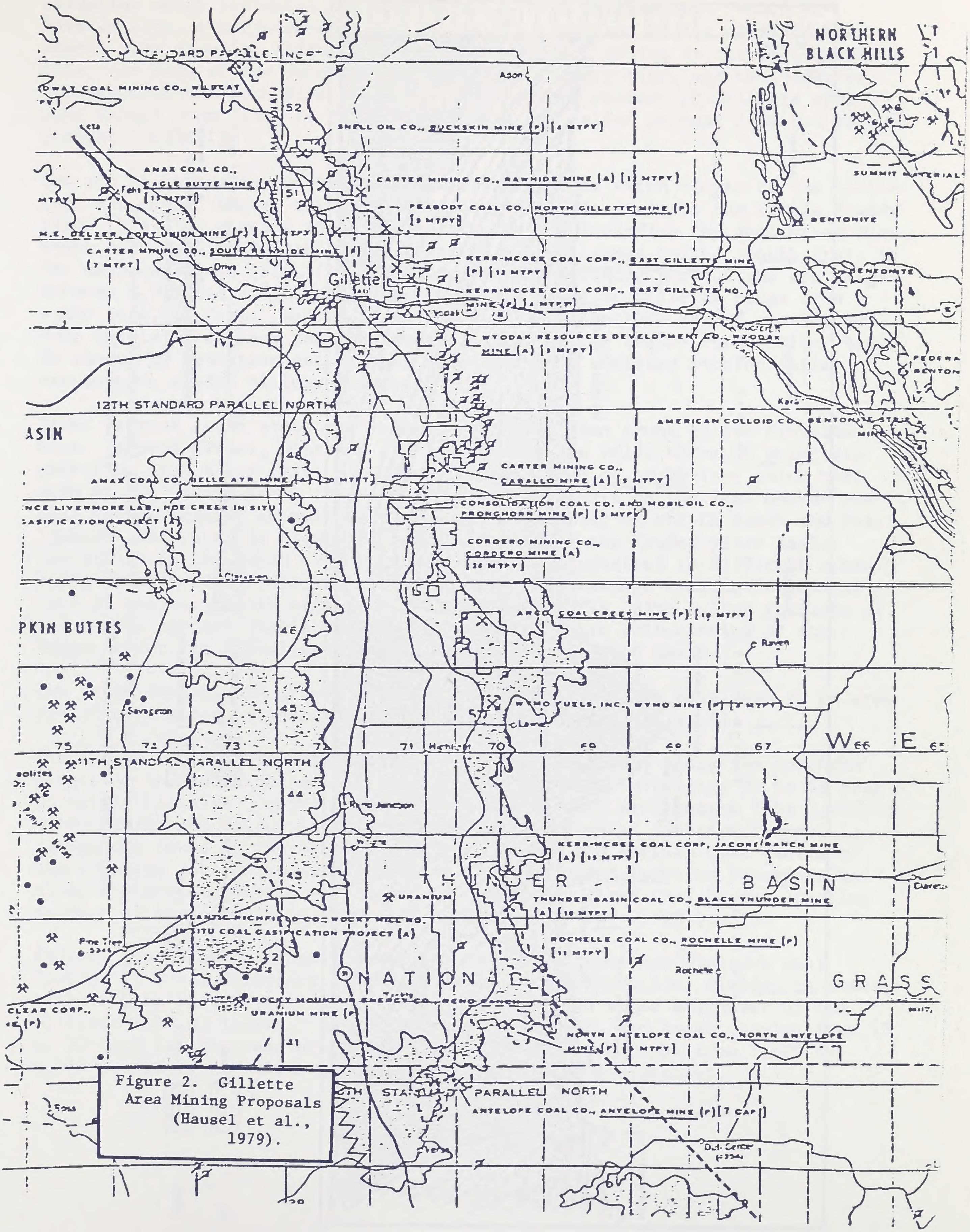
NORTHERN BLACK HILLS
STANDARD PARALLEL NORTH
WILDCAT
Ason
52
SHELL OIL CO., BUCKSKIN MINE (P) [4 MTPY]
ANAX COAL CO., EAGLE BUTTE MINE (A) [15 MTPY]
CARTER MINING CO., RAWHIDE MINE (A) [12 MTPY]
PEABODY COAL CO., NORTH GILLETTE MINE (P) [3 MTPY]
51
SUMMIT MATERIALS
BENTONITE
M.E. DELZER, FORT UNION MINE (P)
CARTER MINING CO., SOUTH RAWHIDE MINE (P) [7 MTPY]
KERR-MCGEE COAL CORP., EAST GILLETTE MINE (P) [12 MTPY]
KERR-MCGEE COAL CORP., EAST GILLETTE NO. 2 MINE (P) [4 MTPY]
Gillette
Wyodak
CAMPBELL
WYODAK RESOURCES DEVELOPMENT CO., WYODAK MINE (A) [3 MTPY]
FEDERAL BENTONITE
49
12TH STANDARD PARALLEL NORTH
ASIN
AMERICAN COLLOID CO., BENTONITE STRIP MINE
48
CARTER MINING CO., CABALLO MINE (A) [5 MTPY]
AMAX COAL CO., BELLE AYR MINE (A) [20 MTPY]
LAWRENCE LIVERMORE LAB., HOE CREEK IN SITU GASIFICATION PROJECT (A)
CONSOLIDATION COAL CO. AND MOBIL OIL CO., PRONGHORN MINE (P) [3 MTPY]
CORDERO MINING CO., CORDERO MINE (A) [24 MTPY]
47
Caballo
50
ARCO COAL CREEK MINE (P) [10 MTPY]
PUMPKIN BUTTES
46
Raven
WYMO FUELS, INC., WYMO MINE (P) [2 MTPY]
Savageton
45
75
74
73
72
71
70
69
68
67
11TH STANDARD PARALLEL NORTH
44
Reno Junction
KERR-MCGEE COAL CORP., JACOBS RANCH MINE (A) [15 MTPY]
THUNDER BASIN
43
URANIUM
THUNDER BASIN COAL CO., BLACK THUNDER MINE (A) [10 MTPY]
ATLANTIC RICHFIELD CO., ROCKY HILL NO. 1 IN SITU COAL GASIFICATION PROJECT (A)
ROCHELLE COAL CO., ROCHELLE MINE (P) [11 MTPY]
Pine Tree
Rochelle
NATIONAL
GRASS
ROCKY MOUNTAIN ENERGY CO., RENO RANCH URANIUM MINE (P)
NORTH ANTELOPE COAL CO., NORTH ANTELOPE MINE (P) [5 MTPY]
41
10TH STANDARD PARALLEL NORTH
ANTELOPE COAL CO., ANTELOPE MINE (P) [7 CAP]
Dull Center
WEE E

Figure 2. Gillette Area Mining Proposals (Hausel et al., 1979).

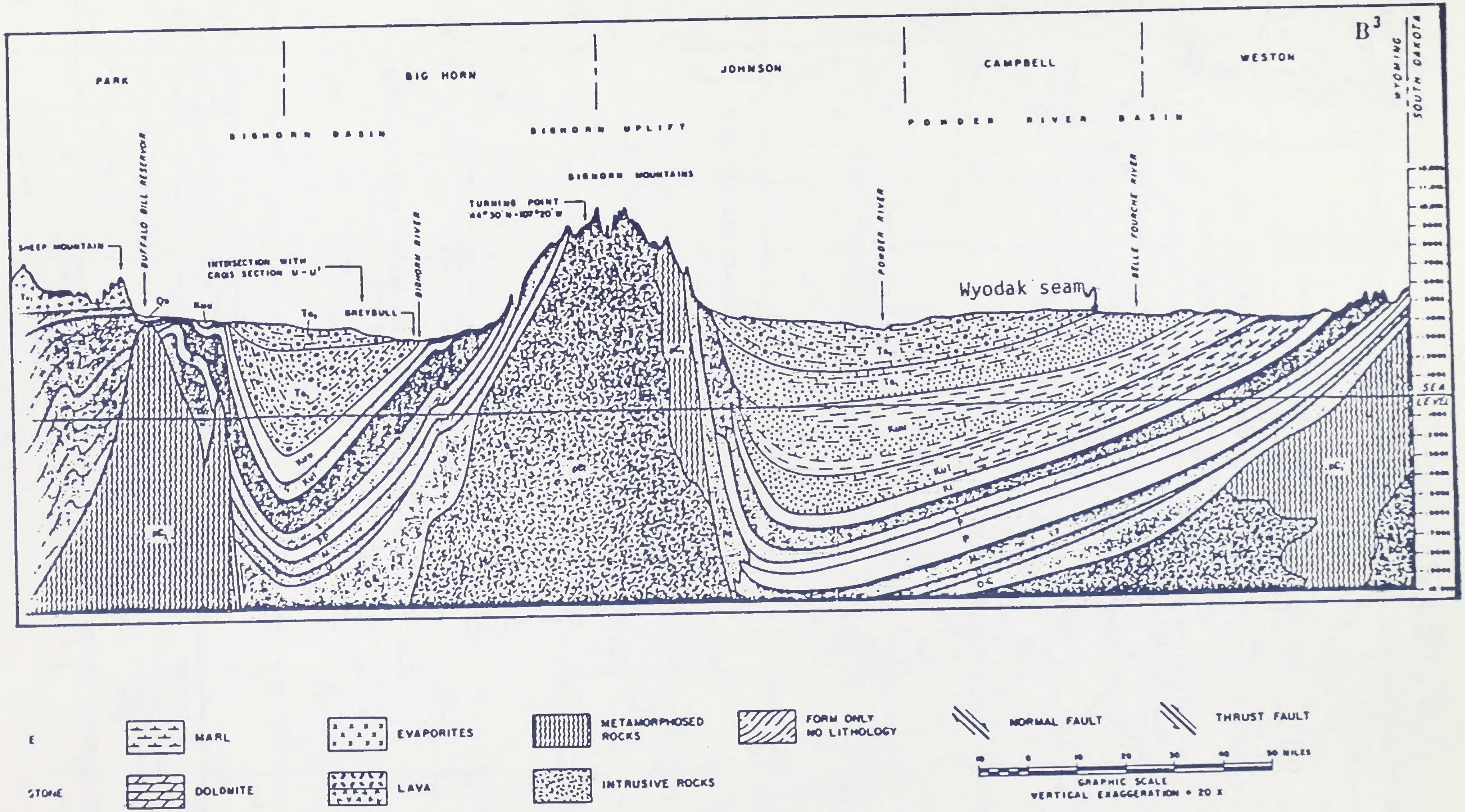

Figure 3. Cross-section across Powder River basin (American Association of Petroleum Geologists 1972; see Fig. 1 for location).

situation which increases the complexity of mine development. South of Caballo Rojo, the Wyodak-Anderson splits, rejoins, and splits again to the south. For example, three seams are the target of mining at the Coal Creek Mine, one seam at the Jacobs Ranch and Black Thunder Mine, and two seams at the proposed Antelope Mine (Fig. 4). The heating content of Gillette area coal ranges from 7,500 to 8,700 Btu/lb, and the sulfur content from 0.3 to 0.5 percent (Table 1).

The arc of leases is located on gently rolling land which slopes to the northeast and east. Leases north of Gillette eventually drain to the Little Powder River (Fig. 5). Leases south of Gillette to and including the Coal Creek Mine drain to the Belle Fourche River (Fig. 6), while leases further south drain to the Cheyenne River (Fig. 7). Elevation in the southern part of the arc ranges between 4,700 and 4,900 feet, and elevations north of Gillette range from 4,200 to 4,400 feet. Relief on any particular leaseblock rarely exceeds 200 feet and is often less than 100 feet. Relief in the entire Powder River Basin is caused by sandstone and clinker beds that have resisted erosion while sreams have eroded valleys elsewhere.

Other Federal lease areas are less concentrated than those of the Gillette area. Around Decker, Montana, six leaseblocks are held, three of which are operating coal mines (Fig. 8). These leases focus on an 80-foot thick coal seam at the Spring Creek lease, which splits eastward on the East Decker and West Decker leases, as well as to the south and west on the CX Ranch and Pearl leases. This area is along the western margin of the Powder River Basin. Variations in the depth of the target seams have resulted in different seams being considered mineable at each property. The average heating content of coal at leases in this area is 9,100 to 9,700 Btu/lb, with sulfur contents of 0.3 to 0.5 percent (Table 2). These leases drain to tributarties of the Tongue River, at elevations ranging from 3,500 to 4,000 feet.

Two large leaseblocks around Colstrip, Montana, are being developed in an area draining to minor tributaries of the Yellowstone River (Fig. 9).

Elevations in this area are about 3,500 feet. This area along the northern margin of the Basin has one of two target coal seams, averaging 20 to 35 feet in total thickness. Heating content of coal in this area ranges from 8,300 to 8,600 Btu/lb and sulfur content from 0.7 to 2 percent. Isolated Federal leases are found in the Sheridan, Spotted Horse, and Buffalo coal fields of Sheridan and Johnson counties, Wyoming. These leases focus on seams exposed along the western margin and center of the Powder River Coal Basin. Heating content of these coals is generally between 6,500 and 7,500 Btu/lb.

Federal leaseblocks are also found in the Dry Cheyenne and Glenrock coal fields, in areas tributary to the Cheyenne and Glenrock coal fields, in areas tributary to the Cheyenne River (Fig. 10), about 25 miles southwest of the Gillette belt of leases. At the Dave Johnston Mine, two seams ranging from 15 to 35 feet in thickness are being mined. These seams range from 7,700 to 8,000 Btu/lb, with sulfur concentrations of 0.5 to 0.6 percent.

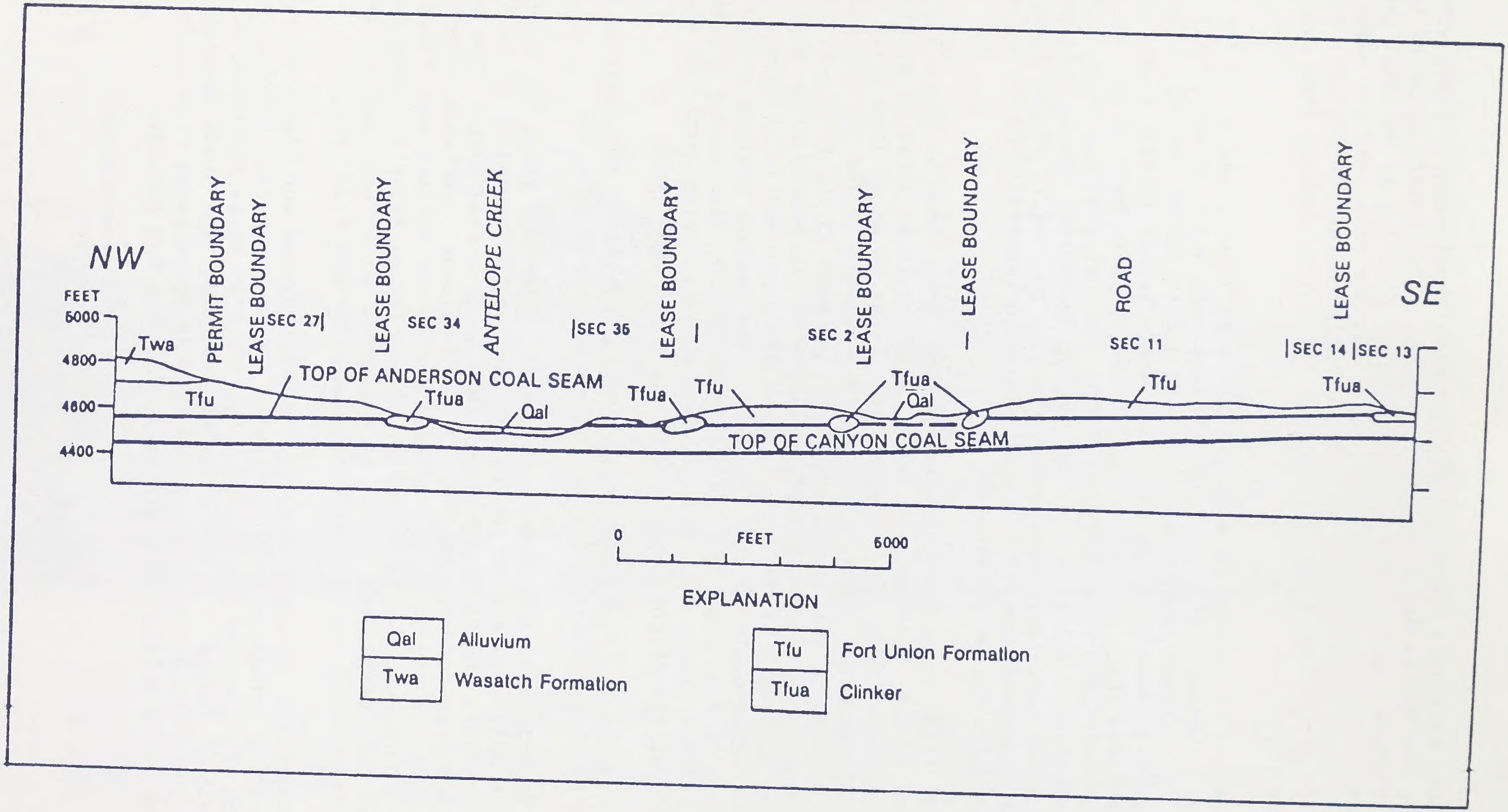

Figure 4. Geologic section, Antelope Mine (U.S. Office of Surface Mining 1981; Fig. III-1).

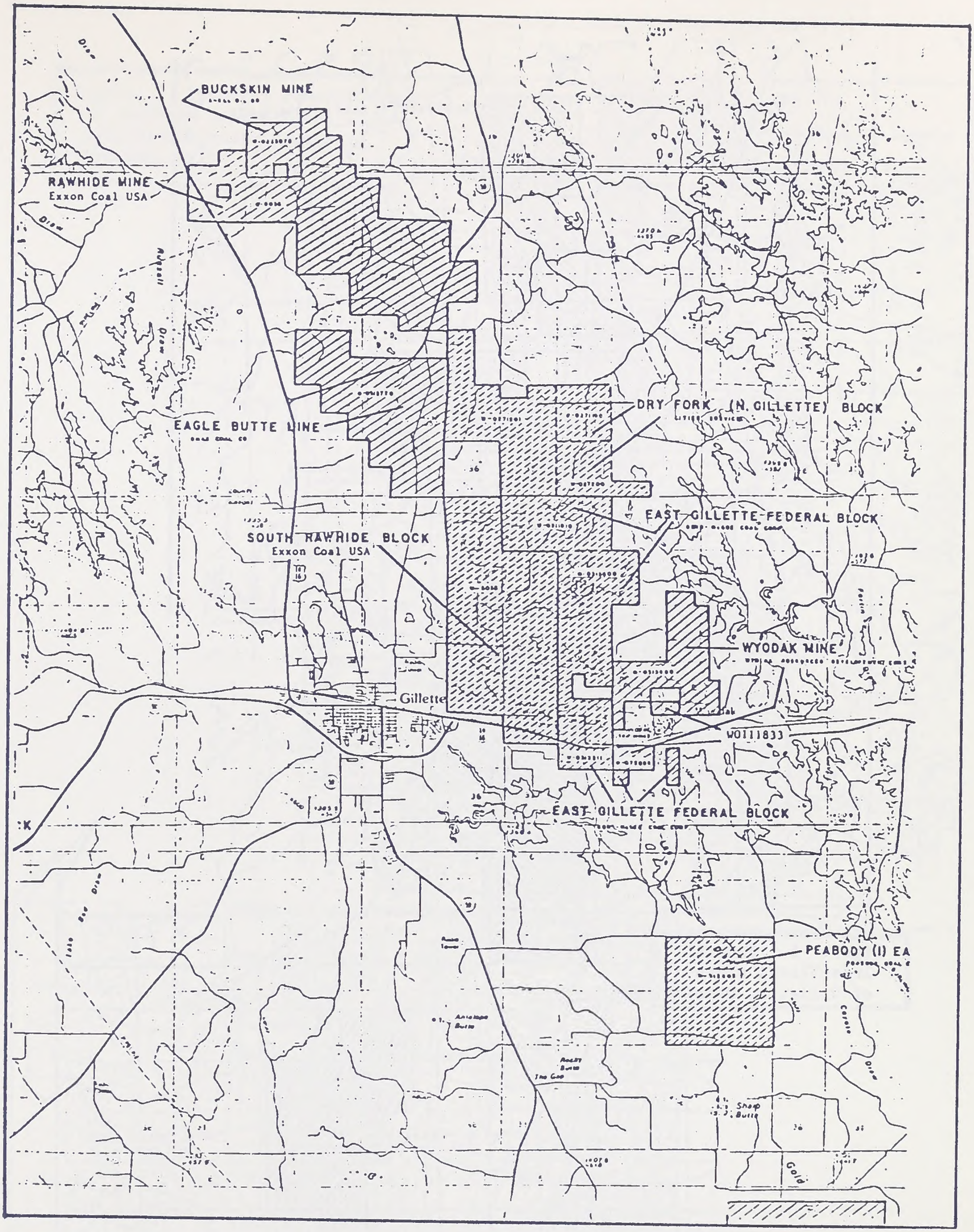

Figure 5. Federal leaseblocks near Gillette, Wyoming.

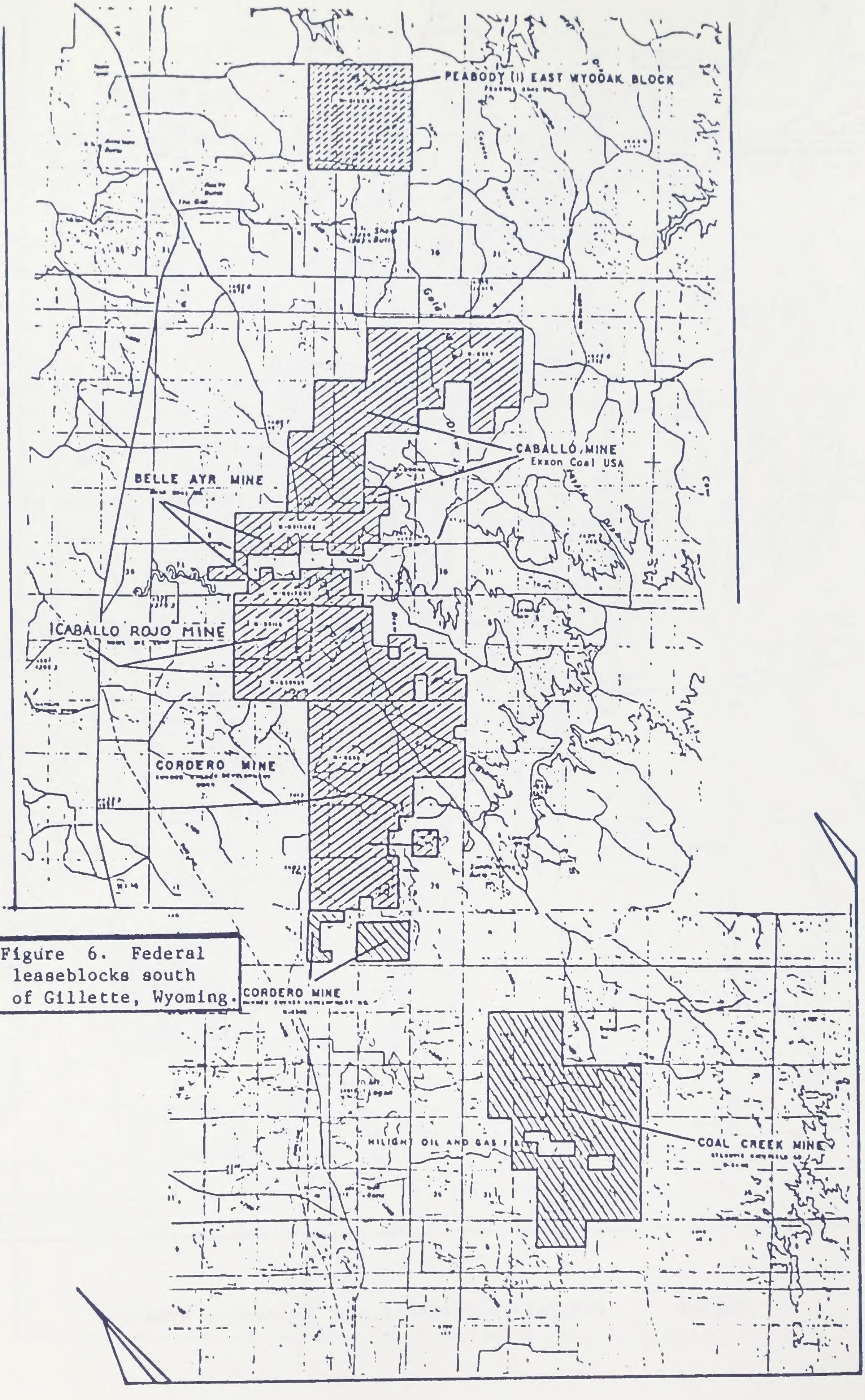

Figure 6. Federal leaseblocks south of Gillette, Wyoming.

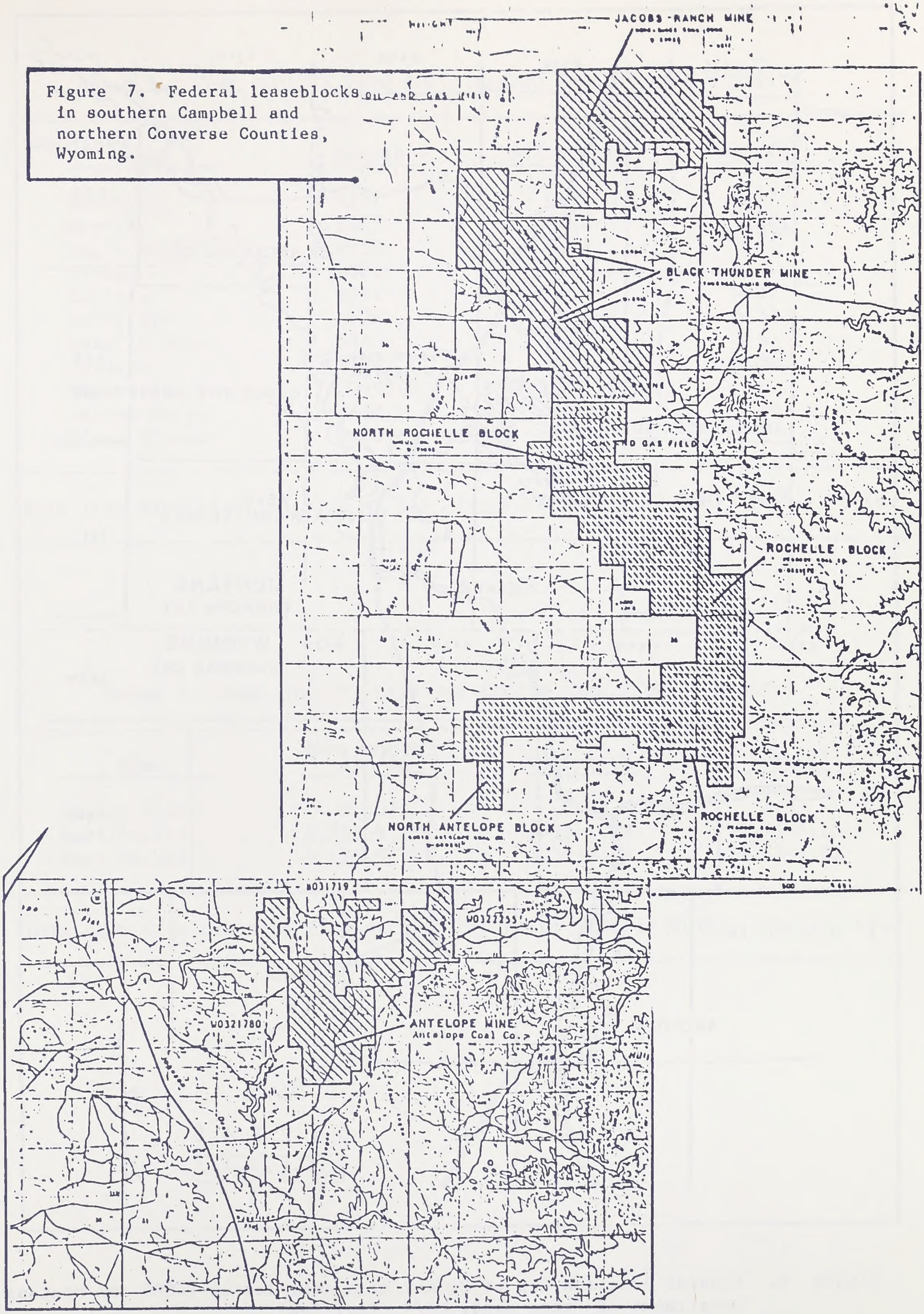

Figure 7. Federal leaseblocks in southern Campbell and northern Converse Counties, Wyoming.

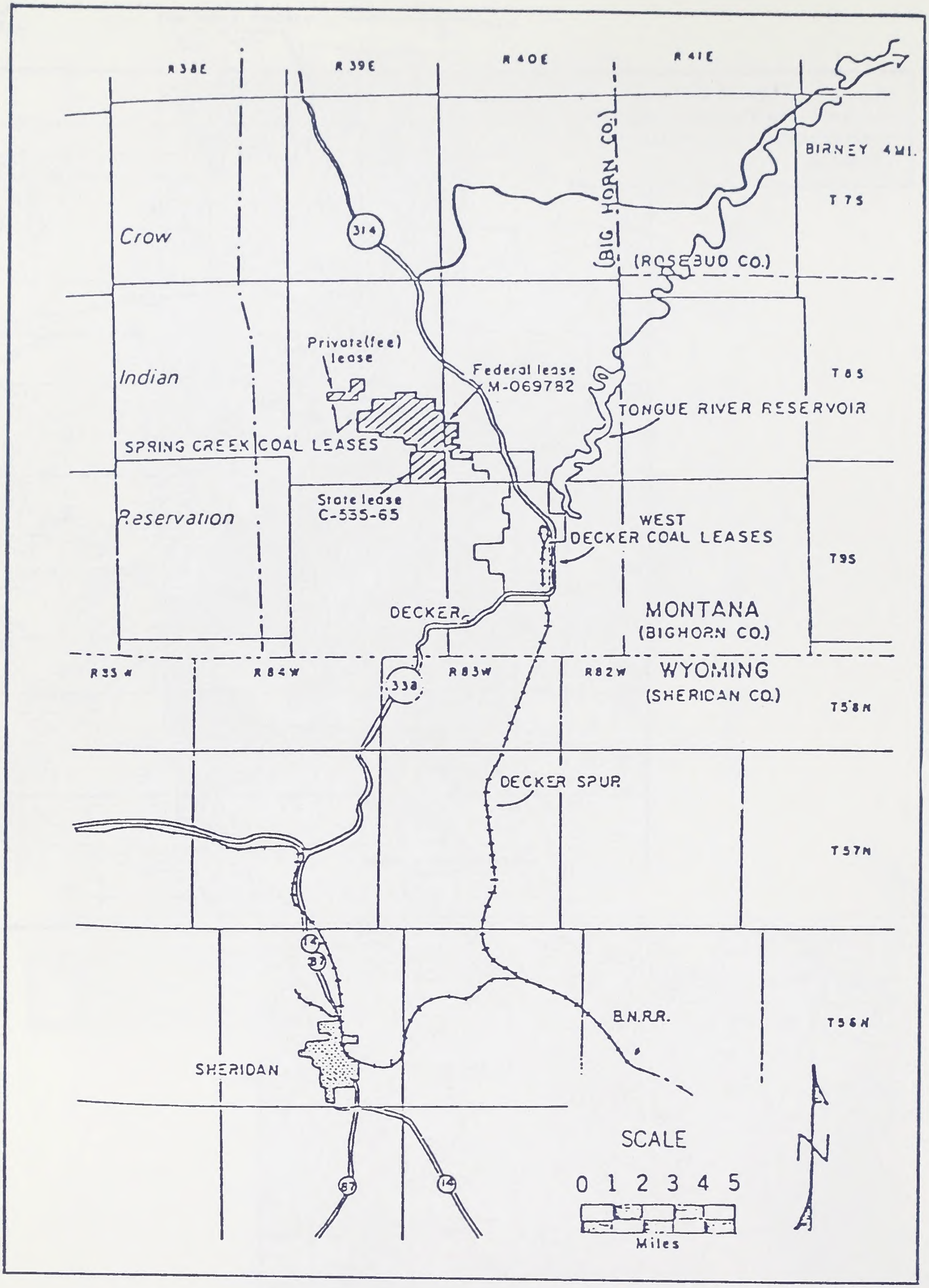

Figure 8. General location map of Decker area coal leases (USGS and Montana Department of State Lands 1979, Fig. I-2).

TABLE 1. COAL QUALITY DATA FOR GILLETTE AREA FEDERAL MINES.*

Mine	Btu/lb	Sulfur (%)	Ash (%)
Buckskin	8177	0.51	6.17
Rawhide	8227	0.34	5.18
Eagle Butte	8282	0.44	5.15
Wyodak	8000	0.5	6
Caballo	8357	0.34	5.27
Belle Ayr	8485	0.36	5.33
Caballo Rojo	8310	0.34	5.6
Cordero	8331	0.33	5.9
Coal Creek	7820-8080	0.32-0.39	--
Jacobs Ranch	8600	0.48	5.89
Black Thunder	8665	0.33	--

*Data from mine plant on file at U.S Office of Surface Mining, Denver, Colo.

TABLE 2. COAL QUALITY DATA FOR DECKER AREA FEDERAL MINES.*

Mine	Btu/lb	Sulfur (%)	Ash (%)
Spring Creek	9,407	0.33	3.63
West Decker	9,262-9,553	0.33-0.38	3.73-5.25
East Decker	9,175-9,707	0.39-0.48	3.67-5.82

*Data from mine plans on file at U.S. Office of Surface Mining, Denver, Colo.

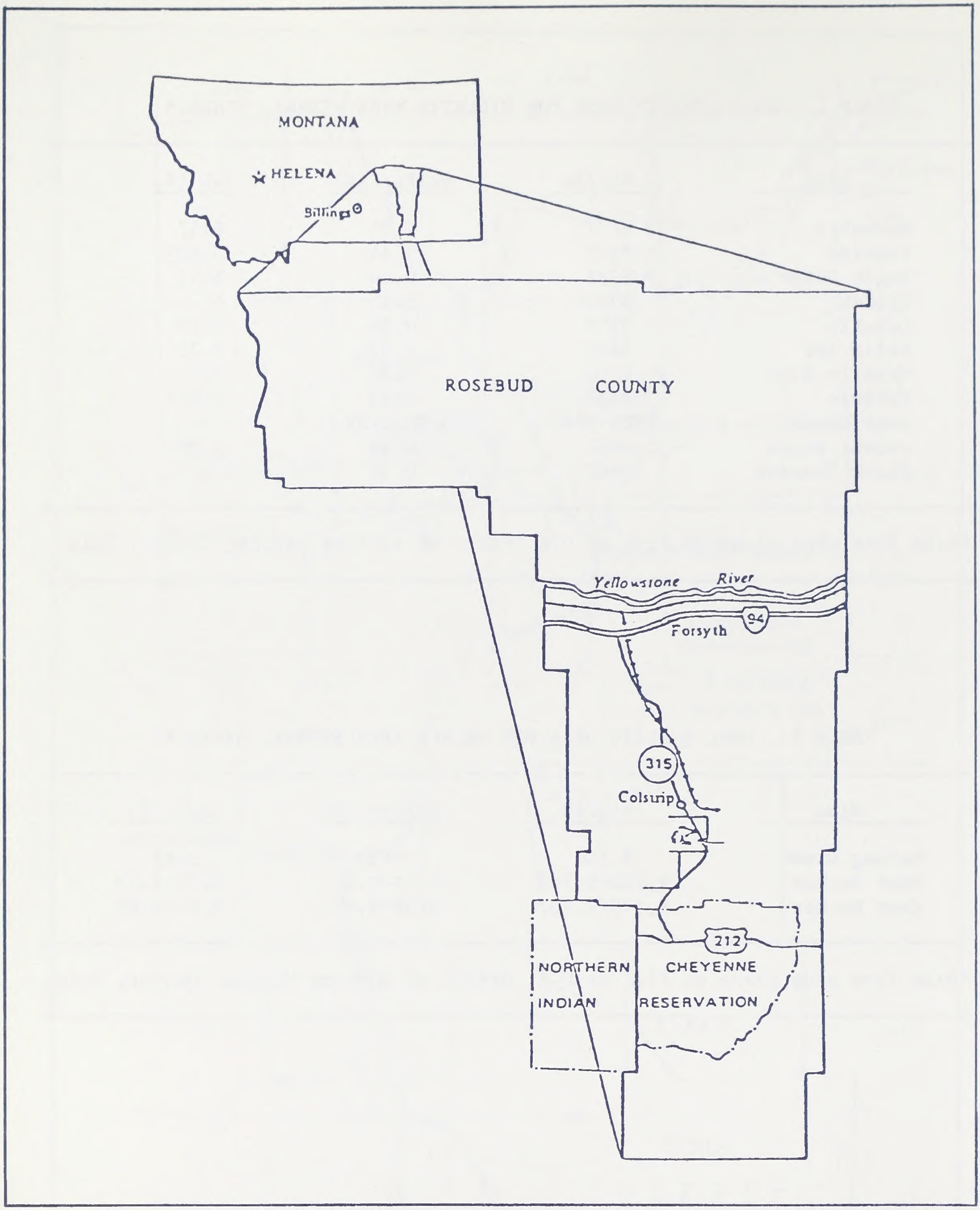

Figure 9. General location of Colstrip, Montana (Montana Department of State Lands and USGS 1978).

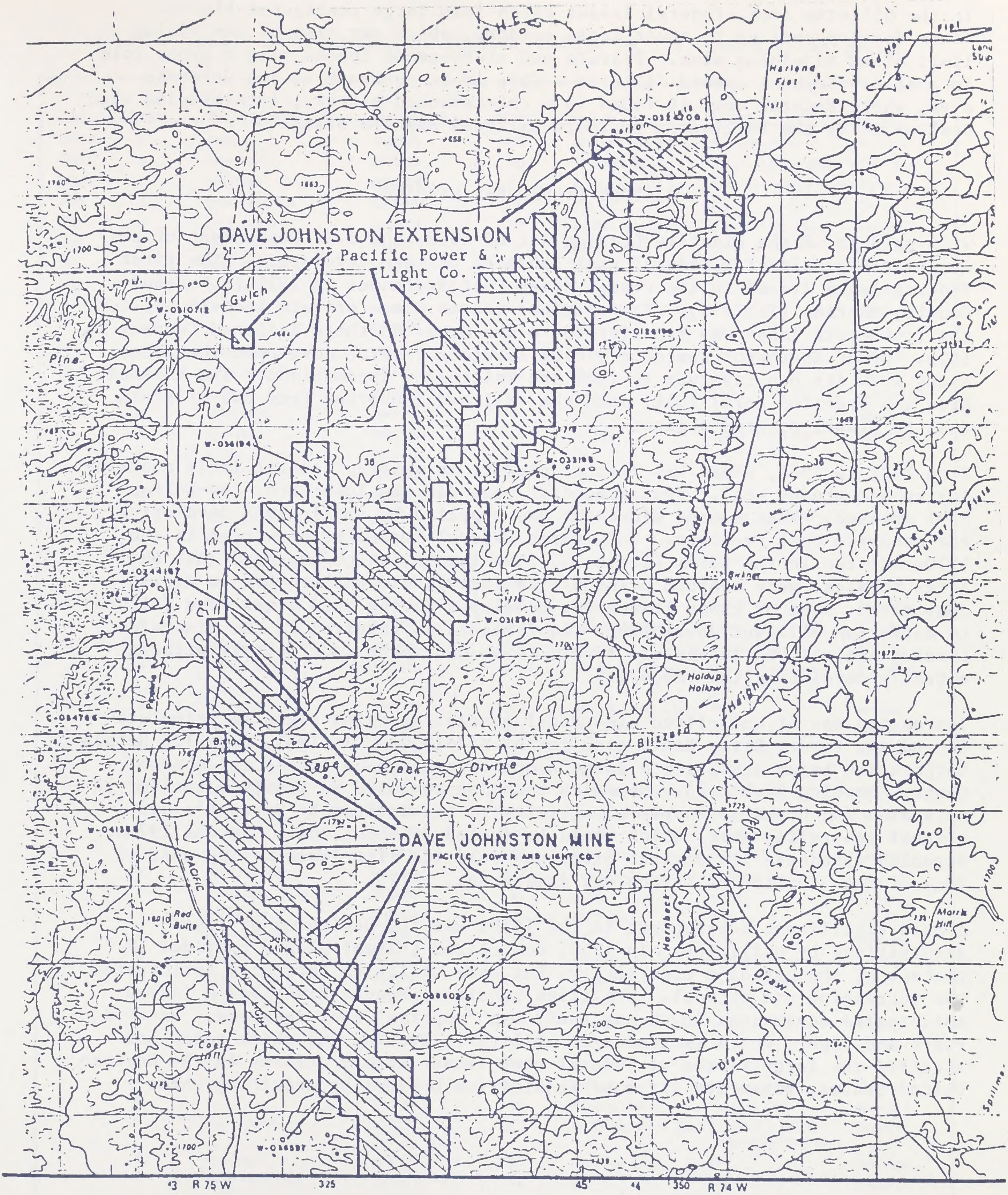

Figure 10. Federal leases in Dry Cheyenne and Glenrock coal fields, Wyoming.

In the Gillette area, Federal leases often form large contiguous blocks. Mines develop coal up to their lease borders, which may also be the mining limit of an adjoining mine. Private and state-owned leases plan a minor role in coal development around Gillette. This is in contrast to the Colstrip area, where Federal coal is found in a checkerboard pattern, intermingled with coal owned by the Burlington Northern Railroad and the State.

HISTORY OF FEDERAL LEASING

With passage of the Minerals Leasing Act of 1920, the U.S. Department of the Interior began leasing Federal coal lands to private developers. The first Federal lease issued in the Powder River Coal Basin was in 1921 in Rosebud County, Montana (Table 3). The original lessee was a private individual, but the 1,446-acre lease was transferred to the Great Northern Railroad Company in 1923. Great Northern created a mining subsidiary which developed the lease along with its own reserves to fuel the railroad's locomotives. The Rosebud Mine was operated until 1958, when the railroad converted from use of steam coal to diesel-powered engines.

From 1924 to 1954, there was little interest in leasing Federal lands containing subbituminous coal. Few commercial uses for the lower Btu, low-sulfur coal existed. What demand did exist was supplied by small mines developing fee or State coal reserves. Only three Federal leases were awarded in the 1930s and two in the 1940s (Table 3). The leases, which averaged just 60 acres in area, were awarded primarily to individuals rather than to mining companies. None of these leases was developed during this time. The failure to establish diligent development requirements as required in the Minerals Leasing Act allowed lessees to retain lease ownership indefinitely without actually developing the resource.

Increasing use of coal-fired electrical generating units began to stimulate demand for Powder River Basin coal in the mid-1950s. In 1955, Reynolds Metals Corporation began acquiring a large block of contiguous leases in Johnson County, Wyoming (Table 3). Reynolds intended to build an aluminum smelter in this area and hoped to supply electricity to the smelter by Reynold's own thermal generating unit, which would be fueled by local coal. In the 1970s, Reynolds abandoned its smelter plans and sold its five-lease mining unit to Texaco, Inc. (Office of Technology Assessment, 1981).

A more significant development in the 1950s was the beginning of lease acquisitions by utilities. In 1950, coal-fired thermal plants provided 19 percent of the nation's electricity, but some utilities correctly anticipated the increasing use of coal. Utilities acquiring Powder River Basin leases anticipated advantages in owning their own "captive" coal reserves. Pacific Power and Light, which is the major utility in Wyoming and which today has acquired the largest area of Federal coal leases of any utility in the Western United States, began its vigorous acquisition program by acquiring three

TABLE 3. BASIC DATA CONCERNING FEDERAL LEASES IN THE POWDER RIVER BASIN.

Year	5tatus	Mine or Leaseblock	Lease Number	Acres	Lessee	Parent	County
1923	A	Rosebud	B020989	1446	Western Energy	Montana Power	Rosebud
1930	U	Armstrong	B025369	80	8ig Horn Coal	Peter Kiewit Sons	5heridan
1932	P	Antelope	B031719	40	Antelope Coal	Pacific Power & Light	Converse
1933	A	Oave Johnston	C054769	120	PPL	PPL	Converse
1944	U	8lue Oiamond	B037423	40	Wyodak Res. Devt. Co.	Black Hills P&L	Campbell
1945	A	West Oecker	M06770	40	Oecker Coal	Peter Kiewit/PPL	Big Horn
1955	U	Lake Oe5met	W030009	1913	Texaco	Texaco	Johnson
1956	A	Oave Johnston	W038597	1400	PPL	PPL	Converse
	A		W038602	2000	PPL	PPL	Converse
	A		W041355	560	PPL	PPL	Converse
1957	U	Lake Oe5met	W051959	320	Texaco	Texaco	Johnson
1959	U	Lake DeSmet	W030052	2203	Texaco	Texaco	Johnson
	A	Wyodak	W073289	240	Wyodak	Black Hills P&L	Campbell
1961	U	Lake De5met	W046349	160	Texaco	Texaco	Johnson
	A	Wyodak	W0111833	80	Wyodak	Black Hills P&L	Campbell
	U	Phillips Creek	W0136194	322	PPL	PPL	Converse
	U		W0136195	1477	PPL	PPL	Converse
	U		W0136196	1560	PPL	PPL	Converse
1963	A	West Oecker	M057934A	1841	Oecker Mining	Peter Kiewit/PPL	8ig Horn
	U	Arvada	W0236621	2551	Gulf	Gulf	Sheridan
	U		W0240559	1620	Gulf	Gulf	5heridan
	A	Oave Johnston	W244167	1803	PPL	PPL	Converse
1964		West Oecker	M057934	720	Oecker Mining	Peter Kiewit/PPL	8ig Horn
	A		M061685	2360	Oecker Mining	Peter Kiewit/PPL	Big Horn
	U	Wolf Mountain	M061686	524	Rosebud Coal 5ales	Peter Kiewit	8ig Horn
	U	CX Ranch	M46292	674	Consolidation Coal	Conoco/Standard of California	Big Horn
1965	A	Spring Creek	M069782	2347	Spring Creek Coal	PPL	Rosebud
	U	Pearl	M069945	541	Shell Oil	5hell Oil	8ig Horn
	U	Arvada	W0236507	195	Gulf Oil	Gulf Oil	5heridan
	U	Wildcat	W0220516	1571	Gulf Oil	Gulf Oil	Campbell
	U	East Gillette	W0312311	880	Kerr-McGee Coal	Kerr-McGee	Campbell
	U		W0313668	2200	Kerr-McGee Coal	Kerr-McGee	Campbell
	A	Wyodak	W0313666	1560	Wyodak	8lack Hills P&L	Campbell
	U	Gulf	W0256663	756	Gulf Oil	Gulf Oil	Campbell
	U	East Wyodak	W0313667	2560	Peabody Coal	Peabody Coal	Campbell
	A	Caballo	W49644	80	Exxon	Exxon	Campbell
	A	Belle Ayr	W0317682	2360	AMAX Coal	AMAX	Campbell
	A	Oave Johnston	W0312918	3779	PPL	PPL	Converse
1966	A	Rosebud	M073109	5792	Western Energy	Montana Power Co.	Rosebud
	A	East Oecker	M073093	9410	Oecker Coal	Peter Kiewit/PPL	Big Horn
	U	Lake OeSmet	W0321120	4821	Texaco	Texaco	Johnson
	A	Black Thunder	W2313	5844	Thunder Basin Coal	ARCO	Campbell
	A		W36094	40	Thunder Basin Coal	ARCO	Campbell
	U	North Rochelle	W71692	2000	5hell	Shell	Campbell
	U	Rochelle	W0321779	8781	Peabody Coal	Peabody Coal	Campbell
	U		W37829	40	Peabody Coal	Peabody Coal	Campbell
	U	North Antelope	W60231	320	North Antelope Coal	Panhandle Eastern Pipeline/Peabody	Converse
	P	Antelope	W0321780	2908	Antelope Coal	PPL	Converse
	U	Phillips Creek	W0310712	40	PPL	PPL	Converse
	P	Antelope	W0322255	1869	Antelope Coal	PPL	Converse

TABLE 3. (Continued).

Year	Status	Mine or Leaseblock	Lease Number	Acres	Lessee	Parent	County
1967	U	Bass	W961	20701	R. Bass Trust	R. Bass Trust	Sheridan
	A	Buckskin	W0325878	599	Shell	Shell	Campbell
	A	Rawhide	W5036	5697	Exxon	Exxon	Campbell
	A	Eagle Butte	W0313773	3520	AMAX Coal	AMAX	Campbell
	U	Dry Fork	W0271199	640	Cities Service	Cities Service	Campbell
	U		W0271200	760	Cities Service	Cities Service	Campbell
	U		W0271201	2180	Cities Service	Cities Service	Campbell
	P	South Rawide	W5035	4782	Exxon	Exxon	Campbell
	A	Caballo	W3397	5280	Exxon	Exxon	Campbell
	A	Coal Creek	W3446	5806	ARCO Coal	ARCO	Campbell
1970	U	Belco	W0322794	4551	Belco	Belco Petroleum	Johnson
	U	East Gillette	W0311810	1263	Kerr-McGee Coal	Kerr-McGee	Campbell
	A	Jacobs Ranch	W23928	4192	Kerr-McGee Coal	Kerr-McGee	Campbell
	A		W24710	160	Kerr-McGee Coal	Kerr-McGee	Campbell
	U	Phillips Creek	W0324701	680	PPL	PPL	Converse
1971	A	Big Sky	M15965	4307	--	Peabody	Rosebud
	A	Caballo Rojo	W58112	840	Mobil	Mobil	Campbell
	A		W23929	3119	Mobil	Mobil	Campbell
	A	Cordero	W8385	6560	Sunoco	The Sun Company	Campbell
1979	A	Rosebud	M35734	480	Western Energy	Montana Power Co.	Rosebud
	A		M35735	447	Western Energy	Montana Power Co.	Rosebud
1980	A	Rosebud	M42381	62	Western Energy	Montana Power Co.	Rosebud
	A	Belle Ayr	W72282	41	AMAX Coal	AMAX	Campbell
1981	A	West Decker	M37604	440	Decker Coal	Peter Kiewit/PPL	Big Horn

A - Approved
P - Proposed
U - Undeveloped

leases in Wyoming (Table 3). Black Hills Power and Light acquired a de novo* lease and an already issued lease by assignment. Montana Power purchased the Colstrip lease from the reorganized Burlington Northern Railroad. The utility companies involved continue to control all of these leases, and all have been developed to supply nearby power plants (Office of Technology Assessment 1981).

The use of coal for electrical generation created an economically attractive market for Powder River Basin coal, both in terms of supply to a local power plant and possible export out of the Basin to other power plants. This new demand began to change the characteristics of a desirable mining unit. The desirability of providing a large, long-term coal supply from a single mine increased the desired size of a typical lease tract and also made it desirable for lease holders to consolidate contiguous leases. Between 1955 and 1959, nine de novo leases encompassing 8,676 acres were issued (Office of Technology Assessment 1981).

Anticipation of greatly increased demand motivated an even greater level of leasing in the Powder River Basin in the 1960s. Between 1961 and 1967, the Federal government awarded 43 de novo leases, compared to 13 leases during the previous 40 years (Table 3). The sizes of leasing units continued to grow. The 126,000 acres leased in the 1960s dwarfed the 10,000 acres leased previously. The Department of the Interior now acknowledges that lands were leased without adequate planning or assessment of demand (Martin 1980). Many leases were also awarded without competitive bidding, through preference-right lease applications.

Anticipation of a growing market for Powder River Basin coal motivated a variety of companies to acquire Federal coal leases. Utilities and coal companies acquired leases in this period, but so did a number of companies and individuals with no prior link to the coal mining or utility industries. Although leases were acquired in many parts of the Powder River Basin, activity focused particularly on Campbell County, Wyoming. Campbell County's exceptionally thick, near-surface coal seams are highly attractive for large-scale surface mining.

Coal companies purchasing coal leases in the 1960s were Peabody Coal, Consolidation Coal, and Ayrshire Collieries Corporation. Individuals, independent land-holding companies, minor oil and gas companies, AMAX, Inc., Peter Kiewit Sons, Inc. (an Omaha-based construction company), and for the first time major oil companies (Exxon and Atlantic Richfield Company) all acquired Basin leases. Approximately half of the de novo leases awarded in the 1960s were later sold to other companies, indicating that many de novo lessees may have been speculating, rather than intending to mine coal. By the end of the 1960s, the Federal government had awarded 56 leases encompassing nearly

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*De novo leases are leases as originally issued by the Federal government through competitive bid or preference right lease application. Once issued, leases can be assigned to another party or segregated into two or more leases.

140,000 acres and 33 mining units. However, only three mines were actually developing Federal reserves at this time: Montana Power's Rosebud Mine, Black Hills Power and Light's Wyodak Mine, and Pacific Power and Light's Dave Johnston Mine. During this period, Peabody Coal opened the Big Sky Mine on fee and State reserves.

In 1970 and 1971, another brief flurry of coal leasing occurred (Table 3). Nine de novo leases were issued, encompassing 25,672 acres. The leases continued to be concentrated in Campbell County. Lessees included a small mining company, minor oil and gas firms, Consolidation Coal, and Mobil Oil. Consolidation Coal was later acquired by Conoco.

Reacting to citizen, State and internal criticism, the Department of the Interior imposed an informal moratorium on coal leasing in 1971, which was formalized in 1973. In 1975, the Federal government attempted to improve its approach to land management by introducing the Energy Minerals Activity Recommendations System (EMARS). The EMARS program depended primarily on the coal industry for identifying specific tracts desired for leasing. The EMARS focus on specific tracts selected by industry diminished BLM's ability to consider leasing alternatives, a conflict with requirements of the National Environmental Policy Act of 1969. Ensuing litigation, Natural Resources Defense Council v. Hughes (1977), ultimately prevented any leasing under EMARS.

No new Federal coal leases were granted between 1972 and 1978, but numerous transfers of existing leases occurred. Most notable was the emergence of major energy companies as the region's largest leaseholders. Texaco acquired the Reynolds Metal Leases, Gulf and Shell acquired leases from land-holding companies, Exxon purchased leases from AMAX, and The Sun Company bought a small mining firm. The trend has continued into the 1980s. In 1980, Cities Service bought some Peabody leases. In 1982, Standard of California became a partner in Conoco's CX Ranch lease. Pacific Power and Light and Peabody, which was acquired by Kennecott Copper Corporation and then by the Peabody Holding Company, also acquired additional leases in the 1970s. Interestingly, none of the utilities acquiring Powder River Basin leases has ever subsequently transferred away a leaseholding.

In the late 1970s and early 1980s, the Federal government had yet to reinstitute a large-scale leasing program. In 1979 and 1980, only four de novo leases affecting 1,000 acres were awarded in the Basin. These were maintenance leases, awarded to allow existing mines to continue operation (Office of Technology Assessment 1981).

In 1982, major energy companies and utilities controlled over 75 perent of the Basin's Federally leased coal lands. The energy firms control the greatest share of the Basin's Federal coal properties. They now operate seven mines (Table 4) and control 40 percent of all leases, 37 percent of leased acreage, and 60 percent of estimated recoverable coal reserves. Utilities control 38 percent of leases, are involved in six mines, control 19 percent of leased acreage, and 11 percent of recoverable reserves. Pacific Power and Light is the largest single leaseholding entity in the Basin. It controls two

TABLE 4. SECTOR OF ECONOMY AND YEAR OF OPENING OF MINE IN POWDER RIVER BASIN.

Public Utility	Mining	Construction	Major Energy	Minor Energy
Montana Power, 1968, 1972,* 1978*	Peabody, 1969	Peter Kiewit Sons, Inc. 1972,* 1978*	Shell, 1981	Kerr-McGee, 1978
NERCO, 1980, 1958	AMAX, 1978 1973		Exxon, 1977. 1979	
Black Hills, Power, 1922			Mobil, 1983	
			Sun, 1976	
			ARCO, 1981, 1977	
New Mines-properties rated favorable or uncertain development properties through 1991 (OTA 1981b)				
NERCO, 1984	Peabody* 1987, ?*	Peter Kiewit Sons, Inc. 1986	Gulf, ?	Kerr-McGee, 1984
				Panhandle Eastern, 1987, ?*
			Exxon, 1984	
			Cities Service, ?	
			Shell, 1985	
			DuPont/Standard of Cal., 1985	

*Joint ventures.

developed mines, is developing another, and operates two jointly with Peter Kiewit Sons, Inc. The Richard Bass Trust (land-holding company) controls the second greatest amount of Federal acreage, but its 21,000-acre lease is considered unfavorable for development. Exxon and the Peabody Holding Company are the Basin's third and fourth largest holders of Federal coal acreage. Other current lease holders include AMAX, Peter Kiewit Sons, Inc., Kerr-McGee, Belco Petroleum, and a small lease jointly held by Peabody and the Panhandle Eastern Pipeline Company.

In 1982, BLM plans to seek competitive bids on new Federal coal leases in the Powder River Basin. These leases are expected to convey 2.2 million tons of Federal coal reserves.

HISTORY OF PRODUCTION

Prior to 1960, only two coal mines operated on Federally leased lands in the Powder River Coal Basin. An export market for subbituminous coal had not yet developed. The Wyodak Mine owned by Black Hills Power and Light provided coal to nearby coal-fired electrical generating plants. Prior to 1958, coal had been produced from Federal leases at Colstrip, Montana, by the Northern Pacific Railroad for use by their locomotives. Basin production in 1960, including production from non-Federal mines, totaled only 1.4 million tons (Table 5).

TABLE 5. PRODUCTION SUMMARY FOR POWDER RIVER BASIN.

Year	Number of Federal Mines	Total Production (Federal and Non-Federal Mines; mmt)
1960	2	1.4
1965	2	2.1
1970	4	7
1975	6	26
1980	12	94

In the early and mid-1960s, 43 new Federal coal leases were awarded in the Basin. No new mines, however, were opened during this period. Production from existing mines expanded to 2.1 million tons (Table 5).

In 1968, a Montana Power subsidiary reopened the Rosebud Mine, which it had acquired from the reorganized Burlington Northern Railroad. A year later, Peabody Coal opened the Basin's first non-utility industry-owned mine, the Big Sky Mine, also in Rosebud County, Montana. Together, these mines produced 3 million tons in 1970, although Peabody's operation had not yet reached full production capacity. Production from existing mines in Wyoming continued to grow. By 1970, Powder River Coal Basin production in Montana and Wyoming reached 7 million tons (Table 5).

AMAX Coal, a subsidiary of AMAX, Inc., opened the Belle Ayr Mine in Campbell County, Wyoming, in 1973. This opening marked the beginning of vigorous development of Federal coal lands in this Basin. A year earlier, Pacific Power and Light and Peter Kiewit Sons, Inc., opened the large West Decker mining complex in Big Horn County, Montana. In 1975, production reached 18 million tons in Montana and 8 million tons in Wyoming. Total production in the Basin rose to 26 million tons (Table 5).

In the 1976-1980 period, mining activity in Campbell County, Wyoming, far overshadowed further expansion of existing mines in other Wyoming counties. Six new mines opened in Campbell County. Four of these mines were opened by major energy companies. The Sun Company opened its Cordero Mine in 1976; in 1977 Exxon and the Atlantic Richfield Company opened the Rawhide and Black Thunder mines, respectively; AMAX opened the Eagle Butte Mine and Kerr-McGee opened the Jacobs Ranch Mine in 1978; and Exxon opened its second mine, Caballo, in 1979 (Table 4). Annual coal production in Campbell County alone rose from 4 million tons in 1975 to 60 million tons in 1980. Federal mines accounted for 96 percent of the County's 1980 production. Total Wyoming production in the Powder River Coal Basin rose to 70 million tons in 1980 (Table 5).

In 1977, Pacific Power and Light and Peter Kiewit Sons, Inc., opened their second joint venture, the East Decker Mine, also in Big Horn County, Montana. Production from existing Montana mines continued to grow steadily. In 1979, Montana production reached 27 million tons, but it fell back to 25 million tons in 1980. This decline is attributed to increased competition in gaining new coal contracts and decreased demand in the Montana coal market areas.

In 1980, 94 million tons of coal were produced in the Powder River Coal Basin. The 12 mines operating on Federally leased lands were responsible for over 90 percent of this production. Mines operated jointly or solely by utilities accounted for the largest share of Federal coal production. Utility-owned or jointly owned mines produced 31 percent of Federal coal. Energy-company-owned mine production, however, has been rising rapidly. Producing nothing in 1975, energy company mines produced 23 million tons in 1980 (Table 5). AMAX, Inc., was the Basin's largest individual producer. Its two Campbell County mines produced 24.5 million tons in 1980, or 28 percent of production from Federal lands.

In 1981, Pacific Power and Light opened its Spring Creek Mine and Shell opened the Buckskin Mine. Already permitted to begin production in the early 1980s are the Coal Creek Mine (Atlantic Richfield) and the Caballo Rojo Mine (Mobil; Table 4).

DEMAND FOR POWDER RIVER BASIN COAL

Future demand for Powder River Basin coal will primarily depend on growth in demand for elecricity from coal-fired generating plants and the cost-competitiveness of Powder River coal relative to coal from other regions.

In 1980, the Powder River Basin accounted for 65 percent of all Western coal production. The Office of Technology Assessment's (1981) evaluation of the issues related to demand for Western coal is particularly applicable to coal from this major producing region. The Office of Technology Assessment (OTA) concludes that growth in electrical use will be the most important influence on demand for Western coal during the next 10 years. Conservation and slower economic growth have caused national electrical growth rates to decline significantly. Between 1945 and 1973, average annual growth in electrical use was 7 percent. The electrical growth rate, however, was less than 2 percent between 1974 and 1979. In 1980, it declined further to 1.4 percent. Analysts feel increased economic activity later in the 1980s will cause the national electrical growth rate to rise moderately (OTA 1981). Projections cited by OTA predict from 2.5 to 4.5 percent growth in nationwide electricity use. Growth in Powder River Basin Coal markets in the south-central and midwestern United States is expected to be higher than the national norm. Growth in Western electrical use is predicted to be lower or near the national average. These regions of the country are the major market areas for the Basin's production.

Another possible source of increased demand for Powder River coal is expected to be conversions in fuel used by electrical generating facilities. Utilities are expected to convert power plants now fueled by natural gas and oil to the use of coal. Conversions are expected to be greatest in the south-central United States, where a high portion of electrical generation is now fueled by more expensive gas and oil. Powder River Basin coal mines already are a major coal supplier to this region and could further benefit from utility conversions to coal-fueled electricity.

Synthetic fuel development and coal exports to Asia are not expected to create a significant market for Basin coal before 1990. It is unlikely that any synthetic fuel plant will be built in the region by 1990. The export market for the Basin's subbituminous coal is reduced by the lower heat content of its coal reserves. Extremely high shipping costs make higher Btu coal from other regions (such as central Utah) more attractive for export. However, NERCO, Inc., a subsidiary of Pacific Power and Light, and Westmoreland Coal have both announced their involvement in construction of export facilities near Portland, Oregon, to handle regional coal exports.

The future competitiveness of Powder River Basin coal will depend upon its ultimate cost advantages to user utilities. Much of the increased demand for Powder River coal in the 1970s resulted from passage of the 1970 Clean Air Act. The Clean Air Act gave the Basin's low-sulfur coal a competitive advantage over coal from many other mining regions. Combustion of some of the Basin coal can meet emission standards without use of stock scrubbers, which can result in a net cost savings for utilities. The 1977 Amendments to the Clean Air Act and 1979 New Source Performance Standards, however, have reduced this competitive advantage by requiring scrubbers on all plants, regardless of the quality of coal burned. The OTA suggests that the full effects of these adjustments will not even be felt until the late 1980s.

The most important competitive advantage now enjoyed by Powder River coal is its low cost per ton mined. Even when adjustments are made for the Basin coal's lower Btu content, its FOB mine price per energy unit (cost per Btu) is much lower than for energy units from other major coal producing regions. Lower production, labor, and reclamation costs make the Basin coal cheaper to mine.

Reducing the mine-mouth cost advantages, however, are much higher transportation costs. Powder River Basin coal must be shipped longer distances by rail to reach major utility market areas. The OTA (1981) reports that rail transport costs per ton for coal shipped to markets outside of the Basin area exceed the FOB mine price of coal. Transportation costs are much lower for coal from regions closer to utility market areas. Rail rates are expected to rise more rapidly than the inflation rate in the 1980s, further exacerbating this disadvantage for Basin coal.

An alternative to rail transport is coal slurry pipelines, which may reduce transportation costs relative to rail; however, it is not yet clear how significant these cost savings will be. A coal slurry line routed southeastward from Campbell County has been planned for several years.

Another transportation option is generation of electricity within the Basin and subsequent transportation of the electricity via tansmission line to market areas. The viability of this option is diminished by the expense of long-distance transmission systems, water availability problems for power plants, and environmental and social impacts of large-scale power plants in the Powder River Basin area.

State coal severance taxes also reduce the cost advantage of Powder River Basin coal. Both Montana and Wyoming impose severance taxes on the mine-mouth price of coal. Montana's 30 percent tax is the highest in the nation and may have contributed to a faster rate of mine development in the Wyoming portion of the Basin. However, OTA suggests other factors also have contributed to the more rapid coal development in Wyoming, as severance taxes account for only a small percentage of the delivered price of electricity and the taxes have not precluded coal development in Montana (Office of Technology Assessment 1981).

Future demand for Powder River Basin coal is expected to grow, but not as rapidly as was predicted in earlier years. Coal demand forecasts have generally been revised downward during the past few years, responding to assumptions of slower electrical growth rates and revisions in air emissions requirements. In 1980, Basin mines produced 94 million tons. The 1985 projections for demand for Powder River coal range from 129 to 223 million tons per year. The OTA chose 138 million and 177 million tons as the most reasonable low and high coal demand scenarios (Fig. 11). Demand projections for 1990 range from 163 to 438 million tons per year; OTA cites most likely demand to range from a low of 199 million tons to a high of 226 million tons per year. Post-1990 projections are conjectural, but 1995 projections cited by the OTA are 306, 386, and 491 million tons per year. The forecast of 491

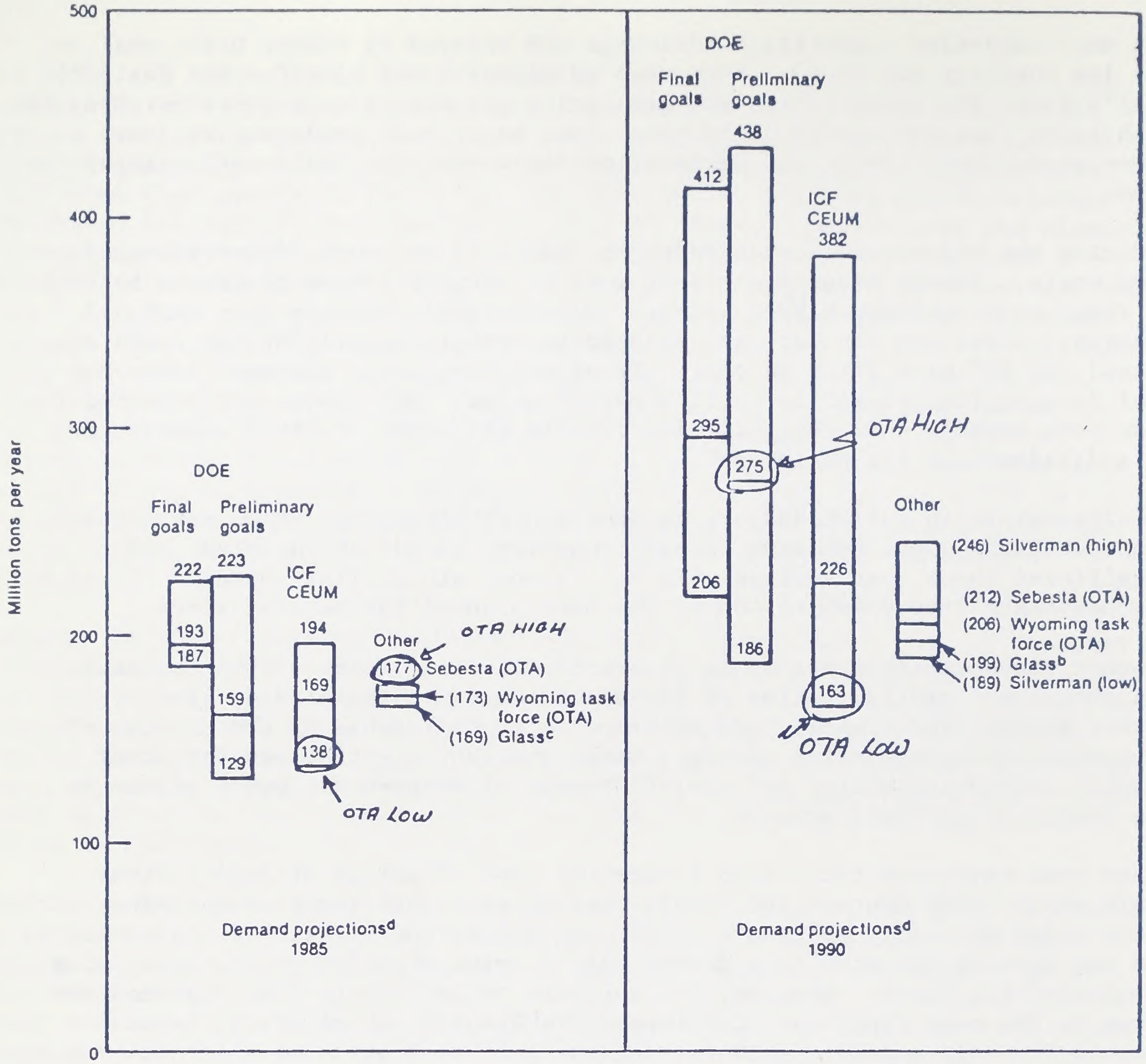

Figure 11. Powder River Basin demand projections (Office of Technology Assessment 1981).

[b] Calculated by adding Sebesta's figure for the Montana portion of the Powder River Basin (66 mmt/yr) to Glass' figure for the Wyoming portion (133 mmt/yr).
[c] Calculated by adding Sebesta's figure for the Montana portion of the Powder River Basin (49 mmt/yr) to Glass' figure for the Wyoming portion (120 mmt/yr).
[d] For 1985 all projections assume zero demand for synfuels and for export to foreign countries from the Powder River Basin. For 1990, see the text for a discussion of synfuels and foreign export demand.

These demand forecasts are:

1. DOE: *Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995* (Washington, D.C.: DOE, August 7, 1980.) See also: *Analysis and Critique of the Department of Energy's August 7, 1980 Report Entitled: "Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995*, prepared for the Rocky Mountain Energy Co. (Washington, D.C.: ICF, Inc., October 1980).
2. DOE: *The 1980 Biennial Update of National and Regional Coal Production Goals for 1985, 1990, and 1995* (Washington, D.C.: DOE, January 1981.)
3. ICF CEUM: *Forecasts and Sensitivity Analyses of Western Coal Production*, prepared for Rocky Mountain Energy Co. (Washington, D.C.: ICF, Inc., November 1980).
4. Sebesta: *Demand for Wyoming Coal 1980-1991 Based Upon Projected Utility Coal Market and Demand for Montana Coal 1980-1991 Based Upon Projected Utility Market* (Washington, D.C.: OTA, October 1980).
5. Wyoming task force: Result of deliberations of the OTA Wyoming task force: Cheyenne, Wyo., October 1980).
6. Glass: *Wyoming Coal Production and Summary of Coal Contracts* (Laramie, Wyo.: Wyoming Geological Survey, 1980).
7. Silverman: Preliminary Results from A. Silverman. University of Montana, Missoula. Private communication to OTA. Work is funded by OSM.

million tons reflects assumptions of substantial synthetic fuel production from Powder River Basin coal; the OTA suggests the lower projections are more realistic.

The OTA indicates several events could cause Powder River Basin coal demand to be somewhat higher than its demand estimates. These factors are: faster than anticipated growth in electrical demand, more rapid than expected conversions from gas- and oil-fueled electricity to use of coal, faster synthetic fuels development using Powder River coal, more rapid and greater coal exports from the Basin, or the possibility that Powder River coal could capture a greater share of the domestic coal market.

ABILITY TO PRODUCE COAL--CAPACITY

As already noted there are now 14 operating coal mines in the Powder River Basin which are at least in part developing Federal reserves. Two additional mines have been permitted and will begin production in 1982 and 1983. Most of these mines are constructing plant facilities, e.g., storage and load-out facilities, to handle substantially more coal than they are currently producing. Thus, if additional markets are identified, these mines have the ability to increase capacity.

Estimates of mine capacity and already contracted production have been assembled (Table 6). These estimates indicate that at Federal mines alone, 70 million tons of additional coal could have been produced if markets had been identified. In 1986, Federal mines that are already permitted expect to be able to produce 220 million tons per year (mmt/yr), of which 154.8 mmt/yr have already been contracted. In 1991, capacity will be increased to 238 mmt/yr of which 157.9 mmt/yr are already sold.

The excess capacity--that amount of annual production which a mine could produce but which has not yet been sold--will be utilized if new markets are gained. The size of the new markets is estimated by different models of coal demand, as discussed in the previous section. Existing and newly permitted mines, however, will not be the only ones competing for the new contracts of the expanding market demand.

One source of competition is existing mines in the Basin which exploit only fee, Indian, or State coal reserves. In 1980, there were five such mines, which collectively produced 11.7 million tons. The Absaloka Mine, operated by Westmoreland Resources, produced 4.9 mmt in 1980; however, it has plant facilities to handle 15 mmty and has mine equipment on hand to immediately produce 10 mmty. Thus, this mine is also competing for new coal contracts.

New mine development, both involving Federal and non-Federal coal, is being planned throughout the 1980s (Table 4). Table 7 summarizes anticipated capacity at planned non-Federal mines in the Basin. Estimates of unsold coal in 1986 and 1991 are 24.1 mmt and 37.6 mmt.

TABLE 6. POWDER RIVER COAL BASIN FEDERAL MINE PRODUCTION, CAPACITY AND CONTRACTS[1]

Mine name	1981 mine design capacity	Production 1980	1986 mine design capacity	Contracts for 1986	Lessees' estimates of production--1986	1991 mine design capacity	Contracts for 1991	Lessees' estimates of production--1991
Montana								
Rosebud	14.2	10.4	19.8	17.8	17.8	19.8	18.0	18.0
Big Sky	4.6	2.9	4.6	4.6	4.6	4.6	4.6	4.6
Spring Creek	0.2	0.1	10.0**	7.0	7.0	10.0**	7.0	10.0
West Decker	10.4	5.5	10.4	5.0	8.0	10.4	5.0	8.0
EastDecker	6.7	5.7	6.7	6.0	6.0	6.7	6.7	6.6
Montana Totals	36.1	24.6	52	40.4	43.4	52	41.3	47.2
Wyoming								
Buckskin	0	0	6.2	6.2	6.2	6.2**	6.2**	6.2**
Rawhide and Caballo	12+7	4.5+2.0	24+12	16.0	24+7	24+12	16.0	24+12
Eagle Butte and Belle Ayr	14+21	8.4+16.1	26+21*	35	24+11	26+21*	35	22+13
Wyodak	3	2.6	5	3.0	3.0	5	5.0	5.0
Caballo Rojo	0	0	9	2.6	9.0	15	2.6	15.0
Cordero	24	6.6	24	10.5	16.0	24	10.5	24.0
Coal Creek	0	0	12	4.8	9.8	12	4.8	12
Jacobs Ranch	16	8.2	16	15.6	15.6	16	15.5	15.5
Black Thunder	20.5	10.5	20.5	17.0	17.0	20.5	17.3	20.5
Dave Johnston	3.8	3.8	3.8	3.7	3.7	3.8	3.7	3.7
Wyoming Totals	121.3	62.7	180	114.4	146.3	186	116.6	172.9
Powder River Basin Totals	157.4	87.3	232	154.8	189.7	238	157.9	220.1

[1] Figures in millions of tons per year (mmt/yr).

*In terms of remaining reserves, capacity is 11 mmt/yr.

**Assumes that additional reserves under alluvial valley floors are permitted for mining.

Source: Schmidt 1982.

TABLE 7. NON-FEDERAL MINE DEVELOPMENT IN POWDER RIVER BASIN, 1986-1991

Likely by 1991	1986 Capacity	1986 Contracts	1991 Capacity	1991 Contracts
Montana:				
Absaloka[a]	15.0	5.1	15.0	5.1
Brophy No. 2	0.2	0	0.2	0
Montco	2.0	0	9.0(12)[c]	0
Young's Creek	--	--	8.0	0
Coal Creek[a]	0.2	0	0.2	0
Totals	17.4	5.1	32.4	5.1
Wyoming:				
Bighorn[a]	4.3	3.0	4.3	3.0
Dutchman	1.0	0	1.0	0
Welch No. 1	1.0	0	1.0	0
Wymo[b]	4.0	2.0	4	2.0
Fort Union[a]	1.5	0	0	0
Clovis Point[a]	5.0	0	5.0	0
Totals	16.8	5.0	15.3	5.0
Grand Totals	34.2	10.1	47.7	10.1

Source: Office of Technology Assessment

[a] Producing in 1980. Total capacity of mines producing in 1980 is 23.5 million tons per year.

[b] Contracts for captive production for utilities. The capacity shown here could probably not be sustained much beyond 1991 without new leasing of Federal coal.

[c] Potential capacity in the 1990s.

There is substantial interest in developing new mines on existing Federal leases. Presently proposed mines for which coal has been sold are the Antelope and North Antelope mines. However, the OTA (1981) estimated that 10 other leaseblocks in the Powder River Basin have favorable development potential, do not yet have coal sold, and have an anticipated capacity in 1991 of 75.3 mmty (Table 8).

The amount of coal actually produced in the Powder River Basin at any specific mine will depend on what the actual demand for the region's coal turns out to be and how successful each lessee is in gaining specific contracts.

Depending on what the demand turns out to be, contracts may or may not be very easy to gain. The OTA (1981) estimated that under its high demand scenario of 275 mmt/yr for 1991, existing mines in conjunction with planned development of other tracts at the pace now contemplated by industry could achieve this production. In fact, planned capacity in 1991 of developed and undeveloped tracts in the Basin will be about 348 mmt/yr (Fig. 12). If the OTA estimated low demand scenario of 163 mmt/yr is realized in 1991, the competition for new contracts will be keen. Contracts already obtained by mines total 186 mmt. Thus, contracts would be decreased, and new contracts would be few. The development of new leaseblocks will thus be an extremely risky venture.

IMPLICATIONS

The comparison of available supply with anticipated demand makes it clear that the ability to produce coal in the Powder River Coal Basin substantially surpasses the market demand for the resource for the next 10 years. A major policy question arising from this oversupply scenario concerns the need for renewed leasing in the Basin in 1982. The OTA (1981) discusses the implications of oversupply to a renewed leasing policy and summarizes the major points of disagreement between pro- and anti-leasing interests. Proponents of renewed leasing cite four basic reasons for their position (Office of Technology Assessment 1981, p. 193):

1. To be able to compensate for the contingencies of incresed demand or shortfalls in supply;
2. To ensure competition;
3. To provide additional reserves for production in the post-1990s to accommodate the 10-year (or longer) lead times needed to achieve full production; and
4. To allow entry of operations not now active in the Powder River Basin for equity and to stimulate competition.

Central to the argument for leasing is the possibility that demand may exceed expectations, creating a shortfall. Depending upon what one considers to be the lead time for new mine startup, leasing in 1982 may be appropriate in order to increase production in 1995. Obviously, expectations of the future of synthetic fuels, the demand for foreign export markets and the efficacy of leasing Federal coal to supply that demand, the growth in electric energy

TABLE 8. PRODUCTION PROSPECTS FOR UNDEVELOPED LEASES: POWDER RIVER COAL BASIN

Development potential	Lessee	Number of leases	Location by County[1]	Acres	Capacity[2] (million tons)	Production prospects[3] 1986	Production prospects[3] 1991
Leases with favorable development potential:							
Antelope	Antelope Coal	3	Converse	4,817	8.0 (12.0)	Favorable[a]	Favorable
N. Antelope	N. Antelope Coal	1	Campbell	320	5.0	Favorable[a]	Favorable
South Rawhide	Carter Mining	1	Campbell	4,782	7.0	Favorable[b]	Favorable
Rochelle	Peabody Coal	2	Campbell	8,821	6.0 (11.0)	Unfavorable	Favorable[e]
Dry Fork	Cities Service	3	Campbell	3,580	8.0 (15.0)	Uncertain	Uncertain
E. Gillette Fed.[h]	Kerr-McGee Co.	3	Campbell	4,343	12.3	Uncertain	Uncertain
N. Rochelle	Shell Oil Co.	1	Campbell	2,000	8.0	Uncertain	Uncertain
CX Ranch	Consolidation Coal/ Standard of California	1	Big Horn, MT	674	8.0	Uncertain	Uncertain
Wolf Mountain	Peter Kiewit Sons, Inc.	1	Big Horn, MT	524	4.0	Unfavorable	Uncertain
Wildcat	Gulf Oil Co.	1	Campbell	1,571	7.0 (10.0)	Unfavorable	Uncertain[e.g.]
Lake DeSmet[e]	Texaco	5	Johnson	9,417	— (20.0)	Unfavorable	Unfavorable[e.g.]
Phillips Creek[c]	PPL	4	Converse	4,039	—	Unfavorable	Unfavorable
Totals		26		44,888	73.3 (112.3)		

Source: Adapted from Office of Technology Assessment 1981b.

[1] Counties are in Wyoming unless otherwise noted.
[2] Numbers without parentheses show capacities for 1991, numbers in parentheses indicate capacities after 1991.
[3] Where footnote appears under "development potential" it is relevant to the development of the lease. Footnotes under "production prospects" are relevant to production prospects only.

Key to Production Prospects:
[a] Coal already under contract
[b] Coal may be combined with contracted production of another mine owned by the same company
[c] Plans to incorporate into existing mine plan
[e] Production contingent on synfuel development
[g] Production contingent on onsite steam electric plant
[h] May be traded under provisions of PL 95-554

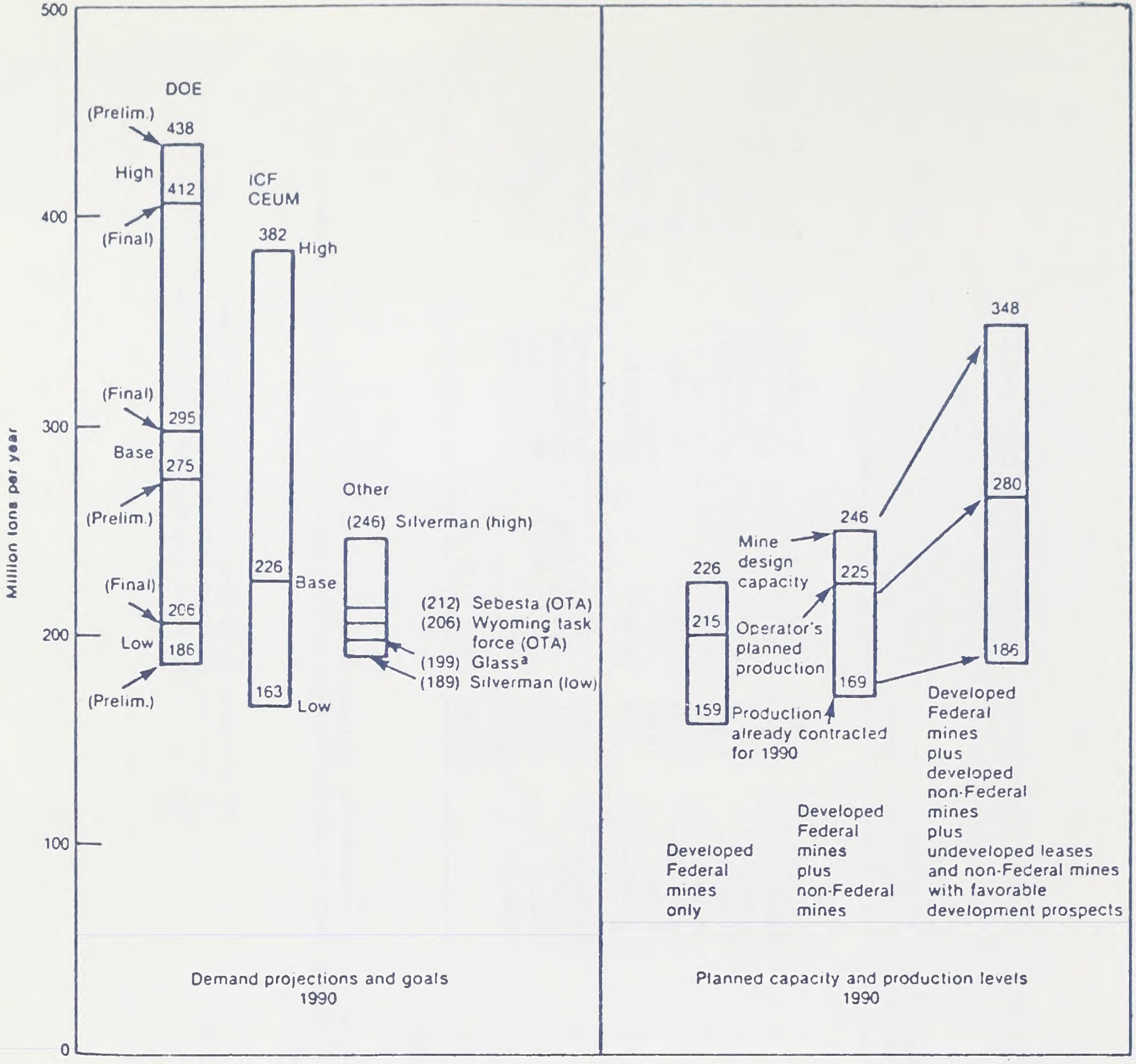

Figure 12. Comparisons of Powder River Basin demand projections with planned capacity and production levels for 1990 (Office of Technology Assessment 1981, Fig. 37).

[a] Calculated by adding Sebesta's figure for the Montana portion of the Powder River Basin (66 mmt) to Glass' figure for the Wyoming portion (133 mmt).

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consumption, and the rate of conversions of power plants to coal sources all affect projections on the future of coal in the Basin.

It is also clear that major energy companies have involved themselves in the Basin in a significant way. Many new mines have been opened by energy majors in the last few years. A notable difference arises about how energy and non-energy companies approach mine development. Energy majors now are operating mines with substantial overcapacities, and these majors are continuing to push additional mine openings. In the absence of any firm contracts, Shell is pushing ahead with large mine proposals at Young's Creek on the Crow Reservation and at North Rochelle. DuPont and Standard of California are pushing the CX Ranch without any contracts. Exxon has proposed the South Rawhide Mine without receiving any contracts. As already noted, Cities Service has acquired leases from Peabody. The availability of excess capital and a desire to move strongly into the coal market seem to be motivating these actions.

In contrast, non-energy companies seem to approach development differently. For example, NERCO, Inc. (subsidiary of Pacific Power and Light), which is the parent to the Spring Creek and Antelope Coal companies, obtains contracts for most of its coal reserves and then uses those contracts as collateral to initiate plant construction (Larson 1980). Peabody has sold all its coal at the proposed North Antelope Mine, and AMAX, Inc., has contracts for most of its reserves at Eagle Butte and Belle Ayr. In fact, the only non-energy mines with significant excess capacity in the Powder River Basin are the Decker Mines, where decreasing electricity demand in the market area has led to deliveries of less than contracted levels.

In considering the impact of new leasing in the Basin, it is important to note that energy majors are at this time willing to invest in mines without a clear idea of who their customers will be. Non-energy companies, with less available capital, are not able to do so. The effect of a highly competitive 1982 lease sale may be to allow energy companies to increase their hold on reserves above what it is today.

The overcapacity issue also has bearing on the argument that environmental regulations are severely affecting the ability to produce Western coal. The OTA (1981) found that less than 10 percent of the 9 billion tons of reserves leased in Powder River Basin have been affected by environmental decisions. Only 1 percent of the total leased reserves, those underlying parts of the designated Squirrel Creek alluvial valley floor at the proposed CX Ranch Mine, have been absolutely prohibited from mining. Only the fee coal Whitney Benefits Mine along the Tongue River in Wyoming has ever been prohibited from development in the Basin, and no Federal mine has ever been prohibited in the Western United States. In light of the fact that overcapacity in the Basin will exist through 1990, it cannot be said that environmental regulations have prevented Powder River Basin coal from meeting its share of national energy needs.

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THE COAL RESOURCE

PHYSICAL AND CHEMICAL CHARACTERISTICS OF COAL

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INTRODUCTION

An unfortunate aspect of studying coal character is that no simple, unambiguous discussion of it exists. The most recent definitive work on the subject is Coal: Its Formation and Composition, by Wilfred Francis (1961). Francis's work reveals the major problem in simplifying what is known about coal character: that coals have been studied locally and regionally for hundreds of years with little effort to synthesize and systematize various data. One result is that the vocabulary of coal character is confusing and ambiguous, since it reflects preferences adopted by students of coal around the world. The British, of whom Francis is one, use a vocabulary and ranking system that is only partly accepted elsewhere. Americans use another. Most attempts at achieving regularity through consensus have failed, leaving scientists with the uncomfortable option of using a partially uniform nomenclature laced with regional coinages.

From the hundreds of localized studies performed worldwide, it is clear that coal is an extremely variable commodity, probably not amenable to a simple system of classification. In one sense, every coal seam is unique, since the peat that formed it derived from a random assortment of detritus deposited over thousands of years. The coal is as unique as the swamp that produced it.

Nevertheless, it is useful to simplify and condense what is known about the coal of a given country, while recognizing that enormous variations exist elsewhere. The present paper attempts to describe the character of coals found in the United States, with emphasis on regional differences between Western and other coals. Much of the information synthesized in the paper comes from non-United States sources and thus wanders away from a strictly American vocabulary for coal character. The reader will encounter all of the terms and data used here in most important textbooks and papers on coal chemistry, formation, geology, and character.

A DEFINITION OF COAL

Coal is sedimentary rock composed primarily of macerals, organic substances derived chiefly from land-plant tissues then compacted and chemically altered by geological and biochemical processes (Neavel 1980). Although coal is principally a stratified mass of altered plant debris and is therefore mostly organic, all coals contain some amounts of inorganic substances.

The natural agents that transform peat into coal includes bacteria and fungi; oxidation, reduction and condensation; and the effects of heat and pressure (Francis 1961). The principal chemical changes that occur as peat is slowly metamorphosed into coal involve chiefly the loss of moisture and volatile constituents accompanied by an increase in the proportions of fixed carbon and ash. The major physical changes involve a weakening of woody cell structure, the development of colloidal properties, a darkening in color, and an increase in hardness, compactness, and specific gravity (Moore 1940, Francis 1961).

Geologists generally consider coal a rock, since rocks are defined as natural, solid substances found in the earth's crust. However, coal is not a mineral by classic definition. Minerals are defined as inorganic, homogeneous substances with definite chemical composition. Coal exhibits none of these characteristics (Moore 1940). While most familiar rocks that comprise the earth's crust are aggregates of mineral grains, coal is an aggregate of maceral particles with small proportions of mineral grains (Neavel 1980).

In classifying coals, two terms are used to describe the relative qualities of various coals. Rank refers to the extent of metamorphic alteration exhibited by a given coal. In the United States, the most common system of coal ranking is one adopted by the American Society for Testing Materials (ASTM). It employs the familiar terms lignite, subbituminous, bituminous, and anthracite to describe the relative ranks of coals. Type refers to the petrographic composition of coals, usually according to what Francis calls coal rock types. Familiar types include vitrain, fusain, clarain, and durain. Each of the types is comprised of various macerals, such as vitrinite, fusinite, resinite, exinite and others.

The term "grade" is also applied to coals to evaluate their technological applications. Grade is usually determined by one or more empirical tests that assess a coal's performance in a particular application. Unfortunately, there is not a well-developed vocabulary to describe coal grades and their relation to rank and type. Many coal users employ their own grading systems (Neavel 1980).

A Glossary of Coal Terms

The following terms are frequently encountered in literature that describes physical and chemical characteristics of coal. Not all of them are used in the present paper.

ALLOCHTHONOUS ACCUMULATION.--Refers to a theory of peat accumulation in which masses of land plants were transported locally by water and deposited in areas favorable for coal metamorphism. Many authors prior to about 1965 believed that such accumulation patterns were responsible for creating major coal deposits around the world, due to the presence of anomalous constituents in certain coal formations. The theory is also known as the "drift theory." Generally it has not been applied to coals found in the U.S.

ANTHRACITE.--The highest ranking coal. It is steel-black, often with a brilliant or even submetallic luster. It burns with a short, blue flame, emits little odor and does not coke. While it contains the most fixed carbon of any rank, its calorific value is lower than that of high-grade bituminous because of the small proportion of volatile matter. It is favored for space heating combustion since it is not dusty, evolves little soot, and burns longer than any other coal. The hardest coal, it is sometimes cut, polished, and used for ornamentation.

ANTHRAXYLON.--The American term for the English vitrain.

ASH.--Any inorganic constituent in coal.

ATTRITUS.--A term coined by Thiessen (1920) to describe the dull components in coals, consisting mainly of miscellaneous peaty debris. Thiessen also coined the term "anthraxylon" to describe bright coal derived from larger pieces of wood. Attrital coals as a type correspond with the British durain (opaque attritus) and clarain (translucent attritus).

AUTHOCHTHONOUS ACCUMULATION.--Refers to a theory of peat accumulation in which masses of land plants were deposited in basins where they remained in place through the development of coal beds. This theory is also called the "in situ" theory of peat accumulation and is now generally applied to most coals around the world. Practically all U.S. coals are believed to be authochthonous in origin.

BITUMEN.--A generic term of naturally derived substances comprised chiefly of hydrocarbons. Common examples are asphalt and gilsonite. Applied to coal, bitumen refers to various esters, waxes, heavy hydrocarbons, and resins that are the primary products of destructive distillation. They can be extracted from coal by using benzene-alcohol solvents.

BITUMINOUS.--A term applied to a broad range of medium to high ranking coals characterized by high caloric value and usually banded appearance. These coals average around 50-65% fixed carbon, 25-40% volatile matter, and 12,000-14,500 Btu per pound. Bituminous coals burn with a yellowish flame and emit suffocating odors. They may be either caking or non-caking, brilliant or dull in luster, and pitch-black to dark grey. Most coal mined in U.S. is bituminous.

CAKING.--Refers to coals that soften and run together into a pasty mass upon heating to the point of destructive distillation. The resulting hard, grey mass is coke, used in metallurgy to reduce metallic oxides or sulfides to metals.

CANNEL COAL.--Originally called "candle coal," this bituminous coal is of a special sort, comprised chiefly of plant spores, low forms of aquatic plants and minute vegetal particles. It contains very high proportions of volatile matter (up to 50%) and thus burns with a bright, lively flame. It is said to be ignitable with a match.

CARBONITE OR NATURAL COKE.--Formed from caking coals when igneous rocks have intruded bituminous coal seams. Carbonite is more compact than artificial coke and contains more residual volatile matter, probably owing to the confinement of gases with evolved-upon destructive distillation.

CHARCOAL OR MOTHER OF COAL.--An antique term for fusain (see explanation under fusain).

CLARAIN.--Refers to a coal type comprised of macerals that originated from various parts of the original plant matter. Clarain contains the greatest variety of plant tissues and structures. In thin sections it is translucent;

thicker sections show a satiny gloss. In the U.S. the term "translucent attritus" is often used in place of clarain. Many authors do not distinguish between clarain and durain as discrete coal types and use only the latter.

COAL MEASURES.--Strata of the Carboniferus or other coal-forming ages containing coal deposits.

COKE.--The solid carbonaceous residue obtained from caking coals after the removal of volatile matter by destructive distillation. Coke is a metallurgical fuel used to reduce metallic oxides to metals.

CUTICLES.--The waxy, water-resistant materials that coat the epidermis of many land plants. In coal formation, cuticles contribute much of the waxy, decay-resistant components that typify some coals. The German "paper-coal" is chiefly made of cuticles.

CYCLOTHEM.--A series of beds deposited during a single sedimentary cycle of the kind that typified the Pennsylvanian (Carboniferous) Period. For example, a common cyclotem associated with many coals is as follows: coal, rootlet bed or underclay, sandstone, non-marine shale or mudstone, marine beds.

DURAIN.--Hard, compact, dull coal is durain, often called "splint coal" in the United States. Comprised of fine granules and rich in spore exines, it is opaque in thin sections. It occurs in thin, irregular bands and breaks with irregular fractures. Durain is a coal type. The corresponding American term is opaque attritus.

EXINES.--The outer coating of spores and pollen grains. Exines deposited in coal-forming peats produce the maceral exinite.

FIXED CARBON.--The portion of carbon in coal that is not driven off with carbohydrates and other volatile materials upon destructive distillation. In proximate analysis, fixed carbon is the difference between the percentage of volatile material and 100. It is the only property that changes progressively and uniformly with increase in rank.

FUSAIN.--A coal type that is porous, dull, friable, and charcoal-like in appearance. It breaks down readily into fine dust and is grayish black. Often its cells are open or filled with mineral matter such as pyrite, gypsum, or clay. Once called mineral charcoal or mother of charcoal, fusain was believed to be altered by combustion in coal seams. It is now believed to be the product of peat "dry-rotted" under aerobic conditions.

INORGANIC SULFUR.--Refers to discrete mineral grains of sulfides and sulfates embedded in coal deposits. The most common are iron pyrites and calcium sulfate or gypsum but other sulfurous salts occur as well. (See Organic Sulfur below.)

LIGNIN.--Also called lignocellulose, this woody, decay-resistant portion of peat comprises much of the plant debris that becomes coal. While cellulose decays fairly rapidly in the bog, lignin often maintains its cellular structure through coalification and remains recognizable in mature coals. According to Thiessen, most plant materials that became coal were 22-35% cellulose and 45-60% lignin.

MACERALS.--The petrographic units of coal that correspond with mineral units of other rocks. Derived from Latin, maceral refers to the maceration of plant materials through coalification. Examples are vitrinite (comprising the coal type vitrain), fusinite (in fusain), exinite (derived from spore exines), and so forth.

MEGALLOCHTHONOUS.--Coined by Francis (1961), this term was intended to distinguish between peats that accumulated through local transportation by water (allochthonous) and those that were transported great distances, perhaps on the sea, after major geological or climatic catastrophes (megallochthonous). Since Francis subscribed to the theories of cyclic catastrophies, advanced by Velikowsky and others, he sought to explain coal formation with similar theories. The term "megallochthonous" has now fallen into disuse but is still encountered in some coal literature.

ORGANIC SULFUR.--Occurs in concentrations as high as 0.5 - 2.0% in certain coals, usually in ones that were deposited in or near marine environments. Unlike inorganic sulfur that occurs as discrete mineral compounds, these occur as organic compounds that remain in plant debris through coalification. It is believed that sulfur bacteria, present in bogs and swamps, produces sulfuric acids that then form sulfates assimilated by plants.

PROXIMATE ANALYSIS.--The determination of moisture, volatile matter, fixed carbon, Btu value and ash in coal, chiefly for the purpose of estimating the components that affect combustion. Proximate analysis determines rank.

RANK.--One way of classifying coal, based on the relative proportions of fixed carbon, volatile matter, moisture, Btu value, and ash. Coals vary in rank from lignites to anthracites, the latter having the highest proportions of carbon and usually ash and the lowest proportions of moisture and volatile material.

RESINS.--Plant compounds that through coalification produce the maceral resinite, an important component of clarain and durain. True oleo-resins are insoluble and sometimes occur in discrete bodies as fossil resins in coal. Many of these are similar to amber. Coals that predate the rise of angiosperms--most of the Carboniferous coals, for instance--derived chiefly from conifers and are therefore richer in resins than later coals.

SEMI-ANTHRACITE.--The rank of coal between semibituminous and anthracite, possessing to a lesser degree the properties of anthracite. It is more friable than anthracite, kindles more readily and gives off a slightly yellowish flame. Its fixed carbon is about 70%, volatile matter about 10%, and it produces 12,000-14,000 Btu per pound.

SEMIBITUMINOUS.--The rank of coal between bituminous and semi-anthracite. It is called "dry" bituminous to distinguish it from "fat" coals such as caking and splint coals that are higher in volatile matter. Semibituminous is perhaps more commonly called low-volatile bituminous coal, and usually contains 11-18% volatile matter, compared with the 32% average of other bituminous coals.

SUBBITUMINOUS.--Officially adopted by the U.S. Geological Survey, this term applies to the broad rank of coal between lignite and bituminous. It is brown-black to pitchy black, and unlike higher ranks it splits into thin slabs along seams that are parallel to the bedding surface. It is also subject to weathering, a characteristic of lower ranking coals. It contains 10-70% volatile matter, 20-80% fixed carbon, and produces 7,000-10,000 (rare) Btu per pound. It is usually low in sulfur.

TYPE.--A way of classifying coals according to physical characteristics and appearance. Systems of typing vary. The British and some Europeans use the terms "vitrain," "durain," "fusain," and (less accepted) "clarain" to describe the major coal types. Each type is comprised of one or more macerals, whose names are derived from the type-names or from plant residues in the coal. American nomenclature uses anthraxylon, translucent attritus, opaque attritus, and fusain to describe coal types. There is little standardization, however, and many American authors use the British nomenclature.

ULMINS.--Organic colloids produced by the decay of peat. Ulmically-derived coals are very important and are often distinguished from others based on original derivatives (e.g., spore coals, resinous coal, attrital coals, etc.).

ULTIIMATE ANALYSIS.--The determination of exact proportions of elemental and mineral constituents in coal. Analysis usually reveals the quantities of total carbon, oxygen, hydrogen, nitrogen, sulfur, iron, and other constituents in a sample coal.

VITRAIN.-- A coal type characterized by a banded appearance and a glossy or vitreous luster. It appears structureless and homogeneous, although thin sections under the microscope reveal compressed woody structures. Vitrain is believed to be comprised exclusively of wood fragments.

VOLATILE MATTER.--Carbohydrates, resins, exines and other constituents that promote rapid combustion of coal are generically referred to as volatile matter. Coalification decreases the proportions of V.M., with a rapid decrease occurring in the formation of anthracite at high temperatures. In coking, destructive distillation drives off nearly all volatile materials, leaving a highly carbonaceous fuel.

COAL FORMATION

> It was now the Missourian Age of late Pennsylvanian time, about 290 million years ago, and the Appalachians were still high but they were no longer alpine. Traveling west and coming down from the

> mountains around DuBois, Pennsylvania, you would have descended into a densely vegetal swamp. This was Pennsylvania in the Pennsylvanian, when vegetation rioted on the earth and the big trees were kings. They were not huge by our standards but they were big trees, some with diamond patterns precisioned in their bark. Other trees had bark like hemlocks and leaves like flat straps. In and out among the trunks flew dragonflies with the wing-spans of great horned owls. Through the high meshing crowns of the trees not a whole lot of light filtered down. The understory was all but woven--of rushlike woody plants and seed ferns. There were luxuriant tree ferns as much as fifty feet high. The scene suggests a tropical rain forest but it was more akin to the Everglades, the Dismal Swamp, the Atchafalaya basin--a hummocky spongy landscape ending in a ragged coast. All through Pennsylvanian time, ice sheets had been advancing over the southern continents, advancing and retreating, forming and melting, lowering and raising the level of the sea, and as the sea came up and over the land in places like the swamps of DuBois it buried them, first under beach sand and later--as the seawater deepened--under lime muds. With enough burial, the muds became limestone, the sands became sandstone, the vegetation coal.
>
> --John McPhee, Basin and Range

To the non-geologist, it is extremely difficult to visualize the landscapes of 300 million years ago, when vast portions of what are now the Americas were covered with seas and lowland basins rioted with vegetal swamps--some of them thousands of square miles in extent--that produced valuable coal. Yet it is the coal itself that allows pieces of the geological puzzle to be put in place, for the coal, like the rocks that sandwich it underground, tells a vivid story.

A generic model of coal deposition provides a basis for understanding the character of various coal deposits as well as the coals themselves. The process that transforms vegetal matter into coal is known as coalification. It begins with the deposition of vegetation in peat bogs, marshes or forest swamps. As layer upon layer of vegetation builds up, anaerobic conditions begin to occur, restricting the amount of bacterial decomposition of the plant tissue. It is important for the formation of coal that decomposition does not occur rapidly, or very thoroughly. It is also important to note that some portions of plant tissues tend to retain their form and chemical composition through peat formation, while other tissues slowly metamorphose in the bog. For example, large woody stems of trees were often transformed into gelatinous ulmins when sufficient acidity existed in the bog.

The low-lying bogs and marshes in which coals were formed were often located along coastal plains that were subject to frequent flooding and sedimentation. As climatic fluctuations influenced the level of Paleozoic seas, the peat bogs were many times flooded for extensive periods, then drained again, allowing new bogs to begin forming on top of fresh alluvium. As seas advanced and retreated over hundreds of thousands of years, they left layer upon layer of sediments that sandwiched and helped metamorphose thick beds of peat. Often, as in coals that are found in the Eastern coal province of the U.S., the periodic sedimentation created many thin seams of bituminous coal that are separated by a few to dozens of feet of sedimentary material. In other coal fields, such as the extensive deposits of subbituminous coals and lignites in the Northern Great Plains, the fluctuations in nearby seas did not occur as frequently--or not at all--allowing thousands of feet of peat to accumulate before sedimentary deposition buried them and hastened coalification.

In any event, the process of converting fresh plant material into coal was similar regardless of the frequency of sedimentation. It is generally recognized that two major steps are involved in coal formation: the first is the biochemical or peat stage; the second, the metamorphic or dynamochemical stage.

A typical forest peat consists of wood fragments embedded in a matrix of disintegrated plant debris. Exposed to the air at the time of deposition, the wood fragments and other tissues begin to decompose, chiefly through bacterial and fungal activity (Francis 1961). Most of the carbohydrates are consumed, but spore exines, waxes, and resins remain substantially unattacked during initial decay. An important decay product, formed chiefly after deep burial and which creates anaerobic conditions in the bog, is ulmin (Francis 1961)--sometimes called humic substance. Ulmins are generally thought to be produced by "wet-rot" under anaerobic conditions created by rapid burial of the peat. After burial, changes in the reduction-oxidation (redox) potential and acidity of the medium begin to inhibit the growth of bacteria, causing decomposition to stop. The resulting ulmin and other products of decay are now richer in carbon and poorer in oxygen and hydrogen. The cell walls in the remaining wood have become thinner, and the cells themselves are compressed as a result of decay. The ulmin, sometimes produced in great quantities in the bog, is essentially structureless, but the cellular structure of the remaining plant sections remains identifiable.

Where aerobic conditions persist through decomposition and acidity is high enough to halt decomposition before the peat is consumed, a different type of peat is formed. Under such conditions of "dry-rot," a coal type known as fusain or mineral charcoal occurs. It is characterized by its dull, non-reflective surface and its relatively high ratio of carbon. Fusain will be discussed in more detail in a later section.

After burial is achieved, the partially decomposed peat begins to metamorphose into coal. The peat, now containing about 60% carbon, is still rich in volatile material. As metamorphism proceeds, the loss of volatile material, accompanied by increasing proportions of carbon, become the chief features of coalification. As long ago as 1873, geologists were recording the relative qualities of coal found at various depths in familiar deposits. Out of these observations came Hilt's law, which stated that volatile matter in coal decreases proportionally to the depth of the seam from the surface (Francis 1961). Later studies showed that for most normal coals, inherent moisture also decreases with depth, while relative proportions of fixed carbon increase.

According to Francis, coal metamorphism can be classified as either normal or abnormal. Normal metamorphism occurs with temperature increases that result from depth of burial associated with earth movements related to folding, faulting, or orogenesis (Francis 1961). Abnormal metamorphism occurs when coals are heated by contact with igeneous rocks, as in areas where igneous intrusions radically alter local coal deposits.

The effect of increased temperature is to accelerate the rate of chemical change in the buried peat. Francis and others maintain that each rise in temperature of 10° C doubles the rate of metamorphism. Since the temperature within the earth's crust rises on the average about 1° C per 100 feet in depth, deep burial under normal conditions would lead to rapid coalification.

Several attempts have been made to estimate rates of metamorphism of peat to various ranks of coal. While they are highly speculative, they do illustrate reasonably accurate relationships between temperatures, time of metamorphism, and increasing carbon ratios in coals. For example, Francis estimates that a minimum temperature increase of 10° C over 67 million years will produce peat that contains 60% carbon. Beyond that stage, minimum temperatures must rise progressively in order to create high ranks of coal, but the length of time for complete metamorphism to occur diminishes. Thus, a consolidated subbituminous coal containing 80% carbon takes only 4 million years to "bake" at a minimum temperature increase of 40° C. Highly carbonaceous coals, such as anthracite (94% carbon) might take less than a million years to form, but the minimum temperature must be as high as 150° C above atmospheric. Such an enormous increase in temperature required to make anthracite implies that the normal heat of burial is insufficient to produce highly carbonaceous coals. Thus they are usually regarded to be the products of increased temperature and pressure caused by folding and faulting as mountains formed.

Where extraordinarily high temperatures occur, such as those that accompany igneous intrusions, the temperature of the coal can soar above the active decomposition point, causing destructive distillation to occur. This is essentially a process of "natural coking," and the resulting product, if sufficiently plastic, resembles coke produced for use in metallurgy. It is also possible for the coal to be completely consumed, leaving large deposits of fused ash underground.

Under normal conditions, coals in a single deposit often vary in rank depending on their location across the field. Such variation is usually attributed to earth movements or varying depths of deposition, both associated with increased temperatures caused by pressure. A noted example in United States coal occurs in the Eastern Appalachian coal measures of Pennsylvania, where folding and faulting created anthracites in the eastern extensions of seams that remain bituminous elsewhere.

A generic model of normal coal formation then occurs as follows: Peat accumulation occurs in lowland areas during periods of mild, moist climatic conditions. The bogs that will eventually produce coal are often situated near a source of rapid sedimentation, such as a broad river delta or a sea.

Bacterial and fungal decomposition of the peat occurs until sediments bury the bog in wet material that effectively seals off the penetration of free oxygen into the peat. Anaerobic, acidified conditions lead to the production of colloidal ulmins in the bog. Eventually, all microbial activity essentially ceases, leaving the partially decomposed peat with some level of increased carbon and decreased hydrogen and oxygen. As the sediment load increases, the peat becomes more tightly compressed. Increasing temperatures caused by sediment loading and various forms of earth movement accelerate metamorphism of humic peat into coaly macerals. As temperature and pressure increase, the coal increases in rank, meaning that its volatile constituents are driven off, it loses inherent moisture and its relative proportion of fixed carbon rises progressively. Portions of the original peat that experienced extensive aerobic decay prior to burial are compressed into the humic coals in the form of fusinite, a highly carboniferous maceral that resembles charcoal. While the formation of carbonaceous peat takes many millions of years to occur, the metamorphism of peat into high-ranking bituminous or anthracitic coals, under optimum conditions of temperature and pressure, could occur relatively quickly.

THE AGE OF UNITED STATES COALS

Textbooks on coal often use shorthand methods, based on geological age, of distinguishing between two broad groups of United States coals. The common shorthand employs Tertiary or Cretaceous to indicate recent, subbituminous coals and Permo-Carboniferous or just Carboniferous to describe the older, higher-ranking coals of the Interior and Eastern Coal provinces. Actually, such shorthand can be quite misleading, since it implies to many readers that younger coals are necessarily of lower rank, while older coals tend toward the bituminous and anthracitic. That is not quite the case. A brief review of coal-dating and the geologic time scale will be useful.

The Carboniferous Period of the Upper Paleozoic Era saw the rise and development of swamp-loving land plants. Climatic conditions favored the growth of tree ferns and early seed-bearing trees, the great gymnosperms. The climate of swampy lowlands remained mild and moist year-round, and seasonal changes were either non-existent or slight, as evidenced by the absence of rings in Carboniferous tree fossils.

It was during this period, about 280 million years ago, that the first coals were deposited in what is now the continental United States. Among commercial coals mined today, the oldest are probably the Pennsylvania anthracites, deposited in warm swamps of the Lower Carboniferous.

Following these deposits, the peats that would become the bituminous coals of the Eastern and Interior Provinces were beginning their metamorphism in the Upper Carboniferous and the Permo-Carboniferous Periods, 220 to 250 million years ago. Virtually all of these coals achieved substantial metamorphism, hence high rank, before the later coals of the Western United States were even deposited. Because of extensive sedimentation followed by thrusting and faulting that created the Appalachian Mountains, all of the Carboniferous and Permo-Carboniferous coals of the United States became bituminous, semi-anthracite, or anthracitic. There are essentially no Carboniferous lignites or subbituminous coals in the United States.

More than 100 million years later, during the Cretaceous Period of the Mesozoic Era, the first Western coals began their development. By the time of the Cretaceous, the angiosperms, or true flowering plants, had evolved and made significant contributions to peats that would become coal. In the Rocky Mountain Province, taking in coals that are now mined in Colorado, New Mexico, Utah, and parts of Wyoming and Montana, earth movements and igneous intrusions helped create coals of bituminous and anthracitic ranks. Virtually all of the commercial coals of the Utah and western Colorado are bituminous, with some semi-anthracites that are mined at Carbondale, Colorado, and a noncommercial deposit of anthracite near Crested Butte.

During the same period and extending through the Upper Cretaceous and into the Eocene, the mammoth peat swamps of the Northern Great Plains were forming. Unaided by the regional metamorphism that created bituminous coals in the Rocky Mountain Province, the coals of the Northern Great Plains became subbituminous and lignite in rank. They are the ultimate products of peats that in places must have accumulated to more than 2,000 feet in thickness. Unlike the shoreline swamps of the Eastern and Interior Provinces, Northern Great Plains coals were not as subject to periodic burial by encroaching marine sediments. Thus the many-layered seams and sediments and thin bands of coal that are common to Eastern coal lands are not the rule among Northern Great Plains coals. Solid beds exceeding 80 feet in thickness are found in many parts of the Fort Union Coal Formation.

While it is useful to recognize that United States coals were deposited during two broad bands of time and that Eastern and Interior coals are much older than Western coals, it is not accurate to portray the younger coals as necessarily lower rank. The same normal and abnormal processes that changed Carboniferous peats into high-ranking coals also produced bituminous and higher ranking coals in Cretaceous deposits.

COAL CLASSIFICATION

Since the beginning of the twentieth century, there have been more systems of coal classification introduced than there are types of coal. As in the case of general coal terminology, every major coal-producing region seems to have its favorite methods of organizing coals into ranks, types, categories, and grades. Some of those methods have been so parochial that they were abandoned soon after coinage. For example, an American, G. H. Ashley, suggested in 1920 that people in the coal business needed a simple, useful classification system that afforded easy comparisons of newly discovered coal deposits with those of known U.S. mining districts. He therefore devised a nomenclature of classification based on the place names of well-known coals. A dedicated geologist, Ashley decided to use the suffix "-ite," familiar to mineralogists, to describe the well-known coals. Thus, Pennsylvania coals in general became pennsites in Ashley's nomenclature. Those bituminous coals peculiar to the Pittsburgh area mines he called pittsite; those from Connelsville became connelsite. Even specific seams entered the new jargon. Coals from the famous Pocahontas coal measure in West Virginia became pocahontite. There were also ohioites, illinoites, and so forth. Unfortunately, as geologists continued making new coal discoveries of coals that had no known correlates in the mining world, Ashley's system began to break down and today it has fallen into complete disuse.

However, other classification systems persisted, although none is yet accepted worldwide as the definitive system. Each of the ones that remain in use today owns its advantages and drawbacks. And while some classification systems aim at absolute definitions of coal character, practical only in laboratory situations, others simply try to describe coals in terms of their applicability in commerce and industry.

In any event, classifications are made according to rank, type, grade, or some combination of those. All systems of classification rely on chemical and physical analyses. Three of the best known classifications are the Ultimate, Proximate, and Rational analyses, and they will be discussed in the following summary, which describes systems of classification used today in the U.S. and Europe.

Coal Types

Coals are heterogeneous substances derived from organic ingredients. What differentiates one coal from another, in part, is the nature of the peats that formed them. While flora that thrived during the Carboniferous was perhaps not as diverse as today's, it varied enough to form peats that were radically different from one another. Coals mined today, 200 million years later, reflect those initial differences.

While the most abundant component in coal is coalified wood, other ingredients survived decomposition in the bog and manifest themselves in varying degrees in all coals, from lignites to the hardest anthracites. In fact, some coals are dominated by non-woody components. Cannel coals, for example, are exceptionally rich in spore exines, and the behavior of the coal reflects its extraordinarily high proportion of volatile matter. Bituminous coals are chiefly wood-derived, but all of them contain the residues of other plant parts that fell into the bog and maintained some semblance of their original chemistry. There are highly resinous bituminous coals, for example, that are probably the result of peats comprised of primitive conifers. There are coals of various rank that are rich in fossilized spore materials--relics of the enormous tree ferns and alligator-scaled club mosses that dominated tropical to subtropical swamps of the Carboniferous. The later coals, lignites and subbituminous ranks from the Cretaceous, contain the macerated stems of angiosperms, the true flowering plants that did not evolve until the Cretaceous Period.

Coal typing is an attempt to classify coals on the basis of their plant-derived components. Primarily it is a system that recognizes physical, rather than chemical, differences, and while most coal types are observable to the unaided eye, microscopic techniques have added a dimension to coal typing that did not exist for the earliest investigators. The coalified wood, fragmentary cellular tissues, resin bodies, leaves, spores, pollen, plant cuticles, and unidentifiable debris that comprises coal are surprisingly extant in even the most mature coals, in spite of the biochemical and geological transformation that created the final carbonaceous result. Even the processes that reduced mature woods to gelatinous humus in the bog did not always destroy the cellular structure of the wood itself. When thin-sectioning and microscopy of coals became prevalent analysis techniques in the nineteenth century, scientists were treated to the discovery of these cellular forms in coal substances that were believed to be amorphous.

Since Thiessen began his descriptions of coal character in 1920, the science of coal typing has recognized two major components, visible to the eye, in mature coals. Thiessen called them anthraxylon and attritus, and recognized that the former, usually appearing as lustrous bands in bituminous coals, were comprised of coalified wood, while the latter duller bands were a miscellaneous assortment of plant debris. Later investigations showed that the bright-dull dichotomy, while correct in the main, was an oversimplification.

As coal petrology became more refined, investigators began to crack the code of coal's physical composition. Through techniques that came to be known as rational analysis, Francis (1961) began reducing bituminous and higher ranking coals into five major components: resins, waxes, and bitumens; cuticular remains; ulmins or humic substances; opaque matter; and fusain or mineral charcoal. Using the familiar suffix "-inite," Francis and others began to develop a lexicon to describe the elemental physical components of all coals. They are called macerals, and each is named after the identifiable plant parts that survived maceration and metamorphosis in the bog, or after descriptive names given to characteristics that were discernable to the unaided eye.

The four major coal maceral types identified almost universally are vitrain, durain, and fusain. A fourth type, clarain, is not accepted in all countries as being distinguishable from vitrain. All four types are present in many bituminous and higher ranking coals.

The term "vitrain" comes from the same root as vitreous, which means glasslike. It occurs in thin bands in bituminous coal, one-eighth to one-half inch in thickness, and reflects light with an obsidian-like luster. Clarain is usually found in the same coal and is identical except for the definite, minute layering that in clarain is observable with the unaided eye. While vitrain is a glossy, coherent mass that fractures conchoidally upon impact, clarain splits evenly along its obvious layers. The macerals that comprise vitrain are all wood-derived. They include ulminite, collinite, periblinite, and other humus-based compounds that derived from woody lignin and cellulose. The macerals of clarain include all the wood-derived components plus those that are made from exines, cuticle, and other plant residues. Clarain is the most diverse and complex of the coal types. Both vitrain and clarain are commonly called "bright coal" around the world and are recognized as being major components in most bituminous coals. It was bright coal that Thiessen called anthraxylon, after the Greek anthrax (coal) and xylon (wood). In the United States anthraxylon was long used for bright coals, but the term "vitrain" has come into common usage; in Great Britain, vitrain and clarain have maintained popularity in usage.

The two dull coal types, durain and fusain, are very different from each other in origin and character. About all they have in common is that no amount of cutting or polishing will make them shine, for their lack of luster is a function of their origins.

Durain, commonly interbedded in close association with bright coal, is what Thiessen called attritus, which he properly attributed to the non-woody components of coal. Durain has a hard, close texture that appears somewhat granular. It does not fracture cleanly away from clarain, but the two maintain "ravelled edges which interlock" (Stopes 1919). Even after fracturing and polishing, durain maintains its matte-like appearance.

Microscopically, durain represents the matrix of finely macerated plant fragments. Polished sections are often semi-opaque. The most conspicuous components that maintain their original structure are spore exines, probably the residue of large tree-ferns that decomposed in Paleozoic bogs or swamps. In some durains, resin bodies and large cuticles dominate the micro-profile. The petrological units or macerals that comprise durain are exinite, resinite, cutinite, micronite, and others. Very finely macerated particles of wood also occur in durain, although they are seldom dominant.

Fusain, which rarely occurs in concentrations greater than 3% of mature coal bodies, is probably of a different origin than vitrain, clarain, and durain.

For while the latter are the results of slow, steady anaerobic decay after burial in the bog, fusain is probably the result of either rapid aerobic decomposition ("dry-rot") or low-intensity fires that occurred, perhaps through spontaneous combustion, in the moist bog environments.

Fusain is highly carbonized coal that does not necessarily exhibit high rank. Its high carbon content was not the result of intense metamorphosism, as in the highest ranking coals, but of processes that probably occurred prior to burial. Thus, while it is highly carbonized, fusain is not always highly coalified and can therefore be of low rank. In fact, it is sometimes found in lignites and subbituminous coals. Macroscopically, fusan is fibrous or charcoal-like in appearance. It is extremely friable, soils the hands easily, and is dull-opaque. Microscopically, it is comprised of wood tissues with opaque cell walls. Its origin, like vitrinite, was clearly the woody portions of large plants. There is only one fusain maceral and it is called fusinite.

Francis and others have identified ten major macerals that comprise various coals. They include the wood-derived macerals: ulminite, collinite, periblinite, suberinite, xylinite, and resinite; the macerals derived from non-woody plant parts: micronite, exinite, and cutinite; and the unusual maceral fusinite, derived from wood under conditions of aerobic decomposition or fire. These are the building blocks of coal, and all of them can be found together in many high-ranking coals. Some of them, especially those derived from cellulose and lignin, are naturally rich in carbon and poor in hydrogen. Others contribute substantial amounts of volatile matter, since they are rich in hydrocarbons. Cannel coal, discussed earlier, is the common name given to coals comprised chiefly of spores (sporinite) and humic matter. It sometimes contains over 50% volatile matter and burns with a long, yellow, smoky flame. It is so volatile it is reputed to be combustible with an ordinary stick match. Cannel coals were once used for making lamp gas before natural gas become available. There are other examples of coals that are peculiar because they are dominated by certain macerals. In any case, it should be remembered that names given to coaly macerals are not uniformly accepted and are subject to frequent change and misuse. They have not been favorite coal classification tools in the United States, but familiarity with them is important since many of the finest coal analysis techniques have been developed in relation to various maceral groups.

In the U.S., where considerations of practical applicability have dominated coal research, typing coals through the identification of maceral components has not been as popular as empirical testing for coal performance. American terminology reflects that emphasis. Thiessen *et al.* (1931) developed a table of familiar coal types identified in the U.S. It is reproduced in modified form in Table 1.

TABLE 1. THIESSEN'S DESCRIPTION OF COAL-TYPES

Type Name	Relative Anthraxylon-Attritus	Nature of Attritus	Structure
Bright	Anthraxylon predominating	Translucent humic matter; spores and opaque matter	Banded; lustrous
Semisplint	Anthraxylon and attritus nearly equal	Granular opaque matter prominent; humic matter present	Microbanded; compact
Splint	Attritus predominating	Opaque matter predominating; spores present	Microbanded; dull luster
Cannel	Almost all attritus	Spores, humic matter or opaque matter predominating	Non-banded; conchoidal fracture
Boghead	Almost all attritus	Oil algae predominating; humic matter present	Non-banded; conchoidal fracture

From Francis, W. 1961.

Thiessen employed common terms for U.S. bituminous coals as type names. He also added cannels and bogheads since they are found in certain areas of the Eastern Province. While correlation between American and British usage are not exact, Thiessen's terminology has at least rough correlates in Britain. Bright coals are vitrain, semisplints as clarain, and splint coals are durain, which are predominant in English coal measures. Both countries possess cannels and bogheads.

Other familiar type-names used in the U.S. are anthraxylon, translucent attritus, opaque attritus, and fusain (Francis 1961), but the list of types rarely exceeds four. Of greater concern than the minute identification of coaly macerals in the U.S. is the performance of industrial steam and coking coals, estimated through proximate analysis, empirical grading methods, and ulitmately, coal ranking.

Coal Ranks

While macerals are the plant-derived building blocks of mature coals, ranks identify the degree of maturity of any given coal. The familiar terms lignite, subbituminous, bituminous, and anthracite are actually names given to ascending ranks of coal. Two of those, lignite and subbituminous, refer to immature coals--those that have not been metamorphosed beyond the stage of retaining large amounts of inherent moisture and volatile matter and are therefore relatively low in heat value.

As described in the previous section on coal formation, the processes of turning plant matter into high-ranking coal involve both biochemical and dynamochemical (geological) metamorphism. The processes that create loosely aggregated peats are strictly biochemical; the peat then turns to coal through metamorphic processes. It is during the first phases of decomposition in the bog that coal character is partly determined. Depth of burial, the speed of decomposition, and the relative amounts of humic substances produced all contribute to the ultimate degree of coalification achievable in a given peat. Depth of burial in the bog appears to be especially critical, since relative amounts of oxygen in relation to carbon and hydrogen partially determine how carbonaceous a coal will actually become. Peats that are rapidly buried very deep in the bog are less likely to be oxidized and thus contain higher amounts of carbon and hydrogen. They are also more likely to experience more intense heat and pressure as the bog is gradually buried with marine or freshwater sediments.

Ultimately, coal rank is a measurement of the relative amounts of fixed carbon, volatile matter, noncombustible ash, and inherent moisture in coal. But early in the development of coal ranking methods, investigators tended to oversimplify ranking by focusing on only one parameter. For example, the heat content of coal is a relatively good indictor of rank, but its usefulness extends only from lignites thrugh semi-bituminous coals, since semi-anthracites and anthracites, the highest ranking coals, do not contain enough volatile matter to produce exceptionally high heat. In fact, high-ranking bituminous coals produce up to 2,000 Btu per pound more heat than the best anthracites.

Total and fixed carbon content is another parameter that, while a good indicator of rank for most coals, fails to account for anomalous coals rich in fusain and does not apply uniformly even to humic coals. Some bituminous coals, for example, can contain as little as 40% fixed carbon but still outrank a 50% fixed carbon subbituminous coal because of other features (e.g., low moisture, high heat value, etc.).

In the United States, proximate analysis is used to determine rank. Proximate analysis assesses amounts of moisture, volatile matter, fixed carbon, and ash in coal. It does not determine exact amounts of carbon, hydrogen, oxygen, or other elemental constituents in coal. That determination is left to an ultimate analysis, which is much more costly, complex, and time-consuming. Once relative amounts of fixed carbon, moisture, volatile matter, and ash are known, the sample can be compared with other coals to determine its rank.

The American Society for Testing Materials (ASTM 1967) has developed a standardized table of coal ranks. It is reproduced in Table 2.

While the ASTM ranking method is the most widely accepted method in the U.S., it contains one major flaw. Coals of lower rank than high-volatile A bituminous are ranked according to moist Btu content or the thermal value of the coal with its natural bed moisture. The flaw is that natural moisture content of lower ranking coals varies tremendously. Lignites, for example, can contain large amounts of moisture in the humic colloids that are still undergoing coalification, as well as moisture due to groundwater flows in coaly aquifers (Francis 1961). A more accurate method of ranking low-value coals according to heat content would prescribe a standardized method of partially drying coals to a uniform degree, then measuring caloric content. Nevertheless, the ASTM method is accepted in the U.S. and many countries, and for most purposes of ranking it is quite adequate.

Table 3 summarizes the amounts of fixed carbon, volatile matter, moisture, ash, and heat content of peat and coals that are found in the United States. Information in the table is aggregated from Moore (1940), Francis (1961), and state-by-state summaries from the Keystone Coal Industry Manual (1980).

TABLE 2. CLASSIFICATION OF COALS BY RANK[a]

Class	Group	Fixed Carbon Limits, per cent (Dry, Mineral-Matter-Free Basis)		Volatile Matter Limits, per cent (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu per pound (Moist,[b] Mineral-Matter-Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	....	....	2	....	....	Nonagglomerating
	2. Anthracite	92	98	2	8	....	....	
	3. Semianthracite[c]	86	92	8	14	....	....	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	....	....	Commonly agglomerating[e]
	2. Medium volatile bituminous coal	69	78	22	31	....	....	
	3. High volatile A bituminous coal	....	69	31	....	14 000[d]		
	4. High volatile B bituminous coal	....	....	....	....	13 000[d]	14 000	
	5. High volatile C bituminous coal	....	....	....	....	11 500	13 000	
						10 500	11 500	Agglomerating
III. Subbituminous	1. Subbituminous A coal	....	....	....	....	10 500	11 500	Nonagglomerating
	2. Subbituminous B coal	....	....	....	....	9 500	10 500	
	3. Subbituminous C coal	....	....	....	....	8 300	9 500	
IV. Lignitic	1. Lignite A	....	....	....	....	6 300	8 300	
	2. Lignite B	....	....	....	....	....	6 300	

[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 per cent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low-volatile group of the bituminous class.

[d] Coals having 69 per cent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

From American Society for Testing and Materials. 1967.

TABLE 3. AVERAGE PROXIMATE ANALYSES OF PEAT AND U.S. COALS BY RANKS

Rank	Fixed Carbon(%)	V.M.(%)	Moisture (%)[a]	Ash(%)[a]	Btu/lb[b]
Peat[c]	24	60	60	10	5,000-6,000
Lignite[c]	37	41	15	9.5	5,500-7,000
North Dakota lignite	29	27	38	6.2	6,800
Texas lignite	26	30	32	11	7,100
Subbituminous Powder River Basin WY	33.5	31	30	7.9	8,300
High-volatile C Bituminous (ILL)	47-60	40-53	7-12	3-12	11,000-11,600
U.S. bituminous[c]	45-65	25-40	2-10	5-12	12,000-14,500
Low-volatile bituminous (or semi-bituminous) (Pocahontas # 3 WV)	76	17	---	4	14,600
Semi-anthracite[c]	79	10	2	8.8	13,000-15,000
Anthracite[c]	93-97	3-7	3-7	3-30	12,000-14,500

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[a] Calculated on an as-received basis and includes only natural bed moisture.

[b] For coal containing 31% or less volatile matter (lignite through subbituminous), heat content is calculated on an as-received basis. For higher ranking coals, heat content is on a moisture-free basis.

[c] "Average" or typical specimens discussed by Moore (1940).

Data from: Francis 1961, Moore 1940, and Keystone Coal Industry Manual 1980.

Coal ranks, like coal types, exhibit familiar physical characteristics. Peat, while not properly a coal, is characterized by a fibrous or woody appearance. Its color can vary from light brown to black in peats that have been decomposed into the humic hydrogel stage. Lignite, sometimes called brown coal, is most akin to peat in appearance. It is usually brownish black, of woody or xyloid texture, and splits into small slabs upon drying. It is relatively light, with a specific gravity of 0.5-0.9. Subbituminous coal is a rank first applied to black lignite-looking coals by the U.S. Geological Survey. In Germany it is called petchkhole, or pitch-coal, which accurately describes its pitch-like appearance. Subbituminous, or black lignite, coal splits along a surface parallel to the bedding plane and thus into regular slabs like brown lignite. It does not disintegrate into rectangles upon impact like bituminous coal, but like anthracites it sometimes fractures conchoidally (Moore 1940, Campbell 1905). It is not as distinctly banded as bituminous coals. The specific gravity of subbituminous coal is around 1.10.

Bituminous coal exhibits the most variation in appearance, behavior, and applicability. In general, its color varies from pitchy black to dark grey. Its luster and reflectivity, as received, can be silky, pitchy, dull, or earthy. It is usually banded, with alternating layers of lustrous vitrain and broader, dull bands of attritus. Some bituminous coals, such as West Virginia splint coals, are uniformly dull in appearance. Bituminous coal fractures irregularly and generally does not separate into parallel partings like brown and black lignites. Upon hard impact, bituminous coal fractures into small rectangles. Its specific gravity averages 1.30.

The behavior of the bituminous coals under fire is most variable. High-volatile, or "fat," bituminous coals burn with a long, yellow flame and emit suffocating bituminous odors that derive the gases produced by combustion of the volatile matter. Low-volatile, or lean, coals burn with a short yellow-blue flame and do not emit the same noxious gases as fat coals. High-, low-, and medium-volatile bituminous coals can all exhibit caking and coking characteristics, and all three ranks can be used for metallurgical purposes. The coking potential of a coal is partly a function of rank (coals below bituminous and above semianthracite rarely coke) and partly a function of the behavior of certain coaly macerals upon destructive distillation.

Partly, too, it is still a mystery since no one has yet offered a definitive explanation of coking properties. White (1909) observed that most coals possessing a hydrogen to oxygen ratio of 59% or above will fuse and swell well enough to produce coke; ratios down to 55% are less reliable and those below 50% usually will not cake at all. But exceptions to White's rule have partially negated it (Francis 1961). Nevertheless, caking occurs at the point of incipient combustion, when the coal softens and runs together into a pasty mass, and the gaseous volatile constituents escape from the mass in bubbles (Moore 1940). Those caking coals that also swell significantly, according to the Gray-King assay test, qualify as high-grade coking coals (Francis 1961). The test is a standard means of determining carbonization by progressively heating the coal in a partially closed tube and allowing it to swell within the tube's confines. The results are then compared with standard profiles of various coking grades. It must be remembered that some authors refer to fat coals, including caking and splint coal, as bituminous; and to lean bituminous coals as semi-bituminous. The latter can be either caking or non-caking, but it rarely has sufficient agglutinating properties to make coherent coke and is, therefore, seldom used for that purpose (Moore 1940).

Semi-anthracitic coal is pitch-black and lustrous in appearance. It exhibits conchoidial fracturing but not to the degree that anthracites do. It is fairly friable, crumbles more readily than anthracite in the fire, and because of its higher amounts of volatile matter, it burns with a partially yellow flame. It does not emit strong gases or odors, because its concentration of volatile matter is only 7% to 8%. Along with anthracite, semi-anthracite is sometimes called hard coal to distinguish it from "soft" bituminous coals.

In fact, anthracite is sometimes cut and polished for use as an ornamental stone. It is the most dense coal, with a specific gravity of 1.40 to 1.70. It is characterized by an iron-black color and a brilliant, even submetallic, luster. It is non-banded and fractures conchoidally, leading some authors to refer to it as bird's-eye. Anthracite does not soil the hands and does not coke. It burns with a short, pale-blue flame and like semi-anthracite it emits little odor. It burns longer than any other coal and does not swell or agglomerate. Because of those features, it was once highly prized as a domestic fuel. Interestingly, the largest deposits of anthracite, found in eastern Pennsylvania, are among the lowest sulfur coals in the country, averaging between 0.5% and 1.5%. Related bituminous coals found nearby contain 5% to 30% sulfur (Keystone Coal Industry Manual 1980).

More than two dozen authors have offered distinct systems of coal ranking. Their methods and assumptions are too numerous and complex to summarize here. Moreover, investigators in the U.S. have been somewhat more prone than the Europeans to limit coal ranking methods to just a few simplified systems. The ASTM classification system is the best and most accepted example. However, geological surveys and institutions in various states use ranking indices and methods that are not accepted nationwide but are meritorious in their own right. The Illinois State Geological Survey, for example, uses rank index in classifying coals. The rank index is expressed in terms of a range of numbers from low to high that represent the calorific value of moist coal on a mineral, matter-free basis to the nearest 100 Btu. Thus, a Henry Country, Illinois, coal that carries a rank index of 117-121 would have a heat value of 11,700 to 12,000 Btu/lb on a moist but mineral, matter-free basis. That same coal, however, will also be assigned a calorific value, expressed in Btu's per pound, that refers to its heat content with its mineral matter (ash) intact. In this case, the calorific value is 10,700 to 11,200--a lower heat value since inclusion of mineral matter in a pound of coal makes it less pure as an energy source. The Illinois system, employing the rank index, attempts to describe the heat value of coal as prepared for combustion: containing its natural bed moisture but washed of most of its ash. Such systems, used by various coal-producing states, can lead to much confusion.

Nevertheless, all states in the U.S. utilize the standards found in Part 19 of the ASTM Book of Standards, and reproduced in part in Table 2. All coals having 69% or more fixed carbon on the dry, mineral, matter-free basis are classified according to fixed carbon. (Fixed carbon is calculated as follows: 100 minus the sum of moisture, ash, and volatile matter.) Others are ranked according to calorific value (ASTM 1967). Recognition of that simple principle will save confusion.

Regardless of the method employed to determine rank, the following changes occur in coal as rank is progressively increased (Francis 1961):

1. A progressive and uniform increase in carbon content.
2. A decrease in hydrogen, gradually until the carbon content reaches 89%, then more rapidly.
3. A decrease in the proportion of volatile matter caused primarily by destructive distillation.
4. An increase in calorific value until the hydrogen content has fallen below 4.5%; then a slight decrease in calorific value.
5. A decrease in moisture content, particularly in inherent moisture.
6. An increase in absolute density.
7. Over a certain range of ranks and types, the development of coking properties.
8. An increase in luster, reflectivity, and depth of color.

While the above changes in character due to increased rank include both physical and chemical considerations, a later section in this paper will outline briefly the changes in chemical composition as determined by ultimate analyses.

Rank and the Distribution of U.S. Coals

In the United States, the highest ranking coals are generally found east of the Mississippi, in the Eastern and Interior Coal Provinces. But, as discussed in the section titled "The Age of U.S. Coals," such a generality is true in only the broadest sense. It is perhaps more useful to recognize that the coal-bearing strata in areas where regional metamorphism occurred will possess higher ranking coals than areas of little or no metamorphism. That is the case regardless of the age of the coals, the extensiveness of the deposits, or their geographical location.

The oldest U.S. coals are probably the anthracites of Pennsylvania, deposited in the Lower Carboniferous Period of the Upper Paleozoic Era, nearly 300 million years ago. But anthracites also occur in deposits near Crested Butte and Carbondale, Colorado, where intensive contact metamorphism due to igneous activity greatly coalified deposits from the Upper Cretaceous (Keystone Coal Industry Manual 1980). Conversely, the shallow, massive subbituminous deposits of Montana and Wyoming were not favored with the intense heat of igneous intrusions, deep burial beneath marine or continental sediments, or regional metamorphism. They therefore retained a large proportion of their original volatile matter and moisture and did not progress far in rank.

In the Western States, topography is a reasonably good indicator of rank, but it is only a rough guideline. The higher ranking coals, most of which occur in Utah, Colorado, and New Mexico, and are high-volatile bituminous, usually occur in or directly adjacent to mountainous areas. Good examples are the Book Cliffs and Wasatch Plateau coals of Utah, the Uinta Region coals of western Colorado, and the Raton Mesa coals of New Mexico. Coals found in the plains environment are generally, but not always, of lignite and subbituminous rank, as best demonstrated by the Upper Cretaceous coals of the Fort Union and Powder River Basin formations. They are weakly coalified, young coals.

In Colorado, Utah, and New Mexico, bituminous coals are the most abundant and commercially important coal resources available. The Colorado School of Mines reports that 70% of the coal resource in Colorado is bituminous; it includes an identified reserve of 4.2 billion tons of coking coal, important to the steel industry of the western States. Nearly all of Utah's 24.3 billion-ton reserve consists of high-volatile bituminous coals. More than half of the 1.4 billion-ton Book Cliffs deposit is of coking grade. Other important bituminous deposits in Utah provide an additional 15.7 billion tons of recoverable reserves. New Mexico, with over 6 billion tons of strippable, high-volatile bituminous coal deposits, also possesses a 700-million-ton reserve of coking coal in the Raton field, which extends north into Colorado (Keystone Coal Industry Manual 1980).

In the Interior Province (Michigan, Illinois, Indiana, western Kentucky, Iowa), the coals are older, being of Mississippian age, deeper, and more coalified. They are nearly all of bituminous rank, with most of them qualifying as high-volatile bituminous. Illinois coals constitute the largest resource in the Interior Province, and the majority of them are high-volatile bituminous C, with occurrences of high-volatile B coals in southern Illinois and A coals in the extreme southern tip of the State. It is the regional increase in rank from northwest to southeast Illinois, rather than depth of deposition, that characterizes Illinois coals.

In the Eastern province, including the Appalachian coals as well as Pennsylvania and Ohio, regional metamorphism greatly altered the extensive Pennsylvanian and Mississippian deposits. The most striking example is in Pennsylvania, where rank generally increases from west to east, reaching its height in the North and Eastern Middle Anthracite fields. Figure 1 shows the average variation in fixed carbon for Pennsylvania coals. Regional metamorphism accounts for the sharp increase in carbon content from western to eastern Pennsylvania.

Like Colorado, Pennsylvania possesses a broad range of coal ranks, which extend from high-volatile bituminous through the finest quality anthracitic coals in the U.S. Unlike Colorado, however, there are not lignitic or subbituminous coals in Pennsylvania, just as there are not lignitic coals of Paleozoic age anywhere in the United States.

Table 4 identifies total U.S. coal reserves identified by rank in each state. Figures 2 and 3 portray coal reserves and geographical locations of major deposits.

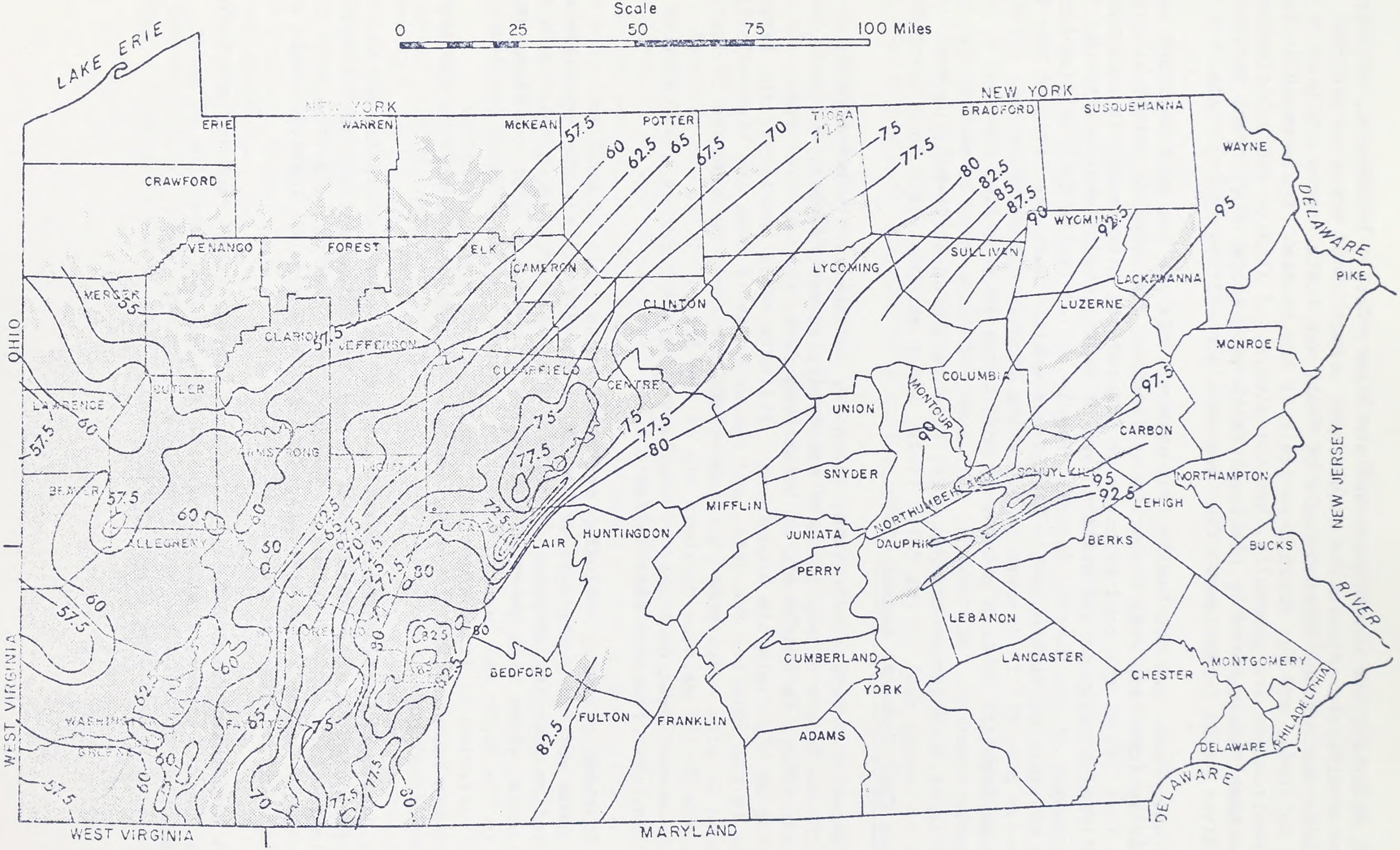

Figure 1.--Isocarb map of Pennsylvania (% fixed carbon; dry, ash-free basis). Source: Keystone Coal Industry Manual 1980.

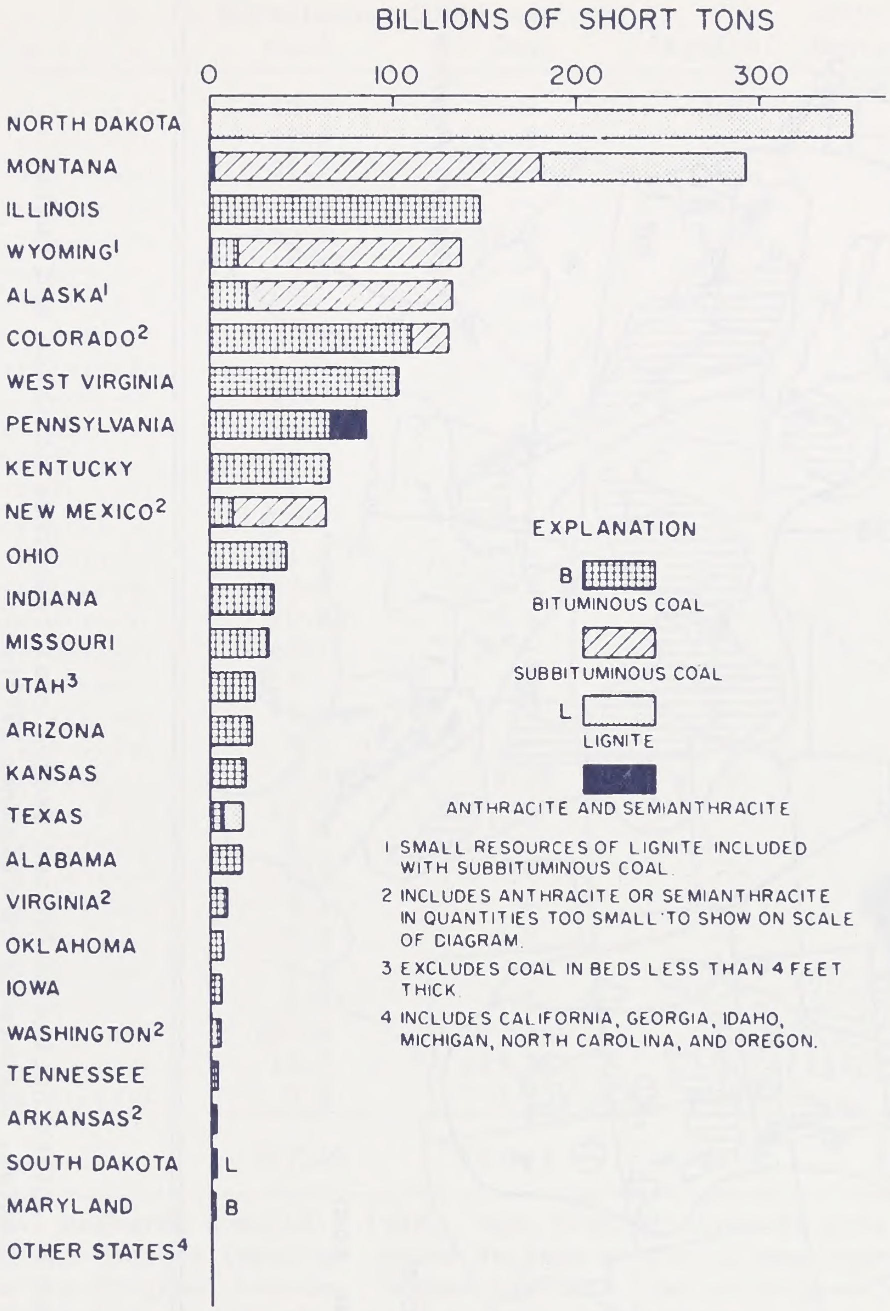

Figure 2.--Remaining identified coal resources of the United States, January 1, 1974, by State (Averitt 1975).

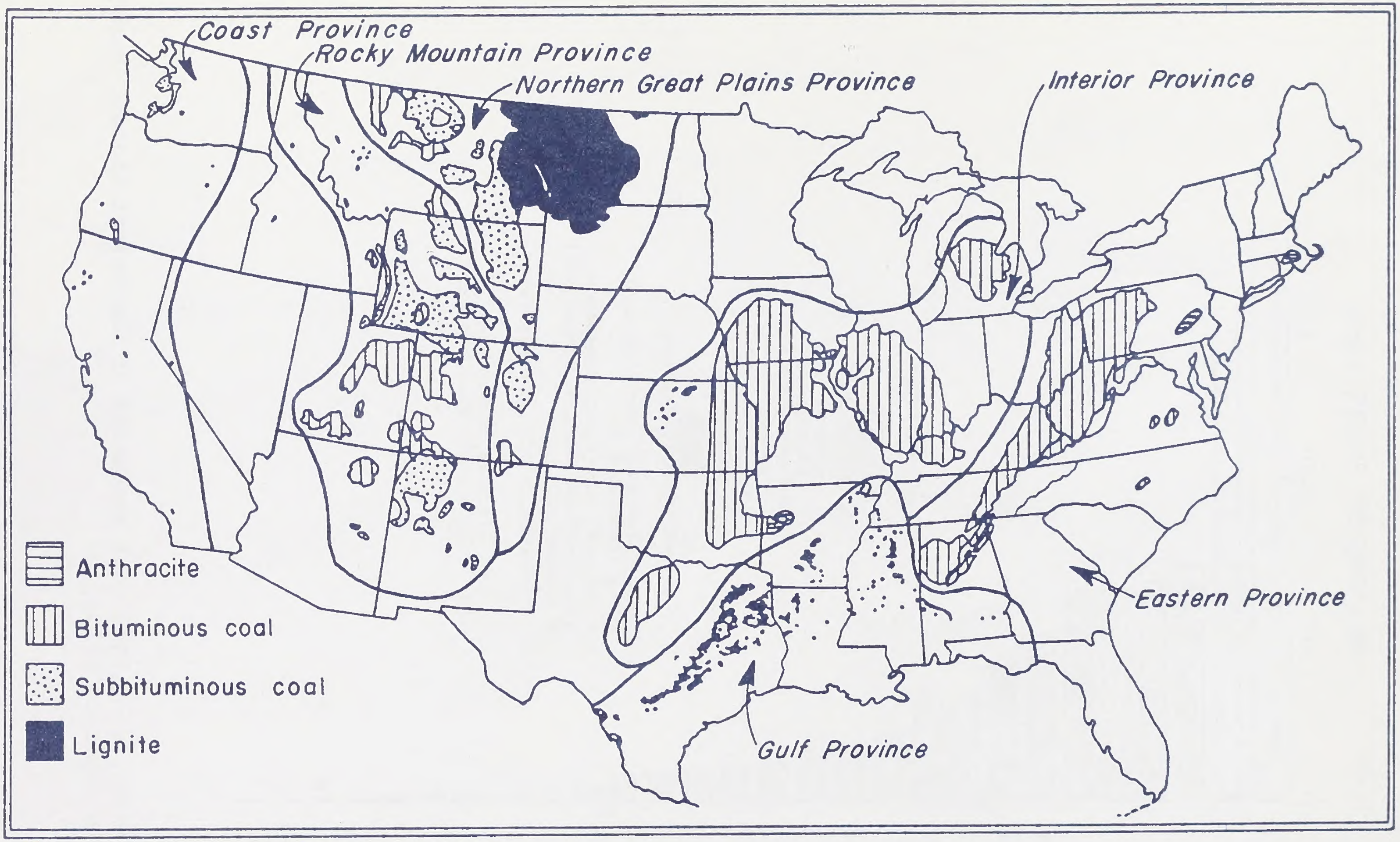

Figure 3. Distribution of United States coal resources (Science and Public Policy Program, University of Oklahoma 1975).

TABLE 4. TOTAL REMAINING IDENTIFIED COAL RESOURCES OF THE UNITED STATES, JANUARY 1, 1974[a] (BILLIONS OF SHORT TONS)

State	Bituminous Coal	Subbituminous Coal	Lignite	Anthracite and Semianthracite	Total
Alabama................	13.3	--	2.0	--	15.3
Alaska.................	19.4	110.7	--	--	130.1
Arizona................	21.2	--	--	--	21.2
Arkansas...............	1.6	--	0.4	0.4	2.4
Colorado...............	109.1	19.7	0.02	0.08	128.9
Georgia................	0.02	--	--	--	0.02
Illinois...............	146	--	--	--	146
Indiana................	32.9	--	--	--	32.9
Iowa...................	6.5	--	--	--	6.5
Kansas.................	18.7	--	--	--	18.7
Kentucky (eastern).....	28.2	--	--	--	28.2
Kentucky (western).....	36.1	--	--	--	36.1
Maryland...............	1.2	--	--	--	1.2
Michigan...............	0.2	--	--	--	0.2
Missouri...............	31.2	--	--	--	31.2
Montana................	2.3	176.8	112.5	--	291.6
New Mexico.............	10.8	50.6	--	0.004	61.4
North Carolina.........	0.11	--	--	--	0.11
North Dakota...........	0	--	350.6	--	350.6
Ohio...................	41.2	--	--	--	41.2
Oklahoma...............	7.1	--	--	--	7.1
Oregon.................	0.05	0.28	--	--	0.33
Pennsylvania...........	63.9	--	--	18.8	82.7
South Dakota...........	0	--	2.2	--	2.2
Tennessee..............	2.5	--	--	--	2.5
Texas..................	6.1	--	10.3	--	16.4
Utah...................	23.2	0.2	--	--	23.4
Virginia...............	9.2	--	--	0.3	9.5
Washington.............	1.9	4.2	0.1	0.005	6.21
West Virginia..........	100.2	--	--	--	100.2
Wyoming................	12.7	123.2	--	--	135.9
Other States[b].........	0.6	0.03	0.05	--	0.68
Total................	747.48	485.71	478.17	19.59	1,730.95

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[a] From National Research Council. 1980. Some figures shown in this table were rounded off to the nearest first or second decimal place and may therefore be slightly different from the original source. Dashes indicate that tonnage is too small to make a noticeable contribution and/or is included under other ranks.

[b] Includes California, Idaho, Louisiana, and Mississippi.

THE CHEMISTRY OF TRANSFORMATION

Now that coal types and ranks have been differentiated and described, a picture of the physics and chemistry of transformation begins to emerge. The cyclothems in which Pennsylvanian coals were deposited and metamorphosed can be likened to a laboratory in which conditions, while not strictly controlled, were at least somewhat regular and predictable.

The accumulating peats quickly began to warm due to the heat of burial or geothermal gradient. Those peats that ended up on the bottom of the pile were destined to become the highest ranking coals of the deposit, assuming that normal load metamorphic processes would characterize the coal-forming regime. Biochemical forces acted on the woody peat, turning most of it into humic jelly. With marine burial, decomposition stopped. All of the biochemical ingredients were now in place, awaiting the heat of further transformation to metamorphose the blackened peat into coal. Tens to hundreds of thousands of years passed, and the sediments gradually lithified into rock. When faulting and uplift began to occur, the beds of immature coal began to assume inclined angles to the original horizontal. Lateral and sublateral pressures lifted coal even farther from the original positions, and with the lifting came intense heat of pressure that rapidly cooked off the hydrogen-rich volatile ingredients in the coal. The seams became more compressed and dense as the ratio of carbon in the coal began to rise. Some of the heating coal agglutinated and began to swell, compressing the mass even more. Eventually the process stopped, leaving a bed of compressed coal, commonly in a highly deformed state.

Physically, the coal had changed a great deal. It became pitch-black and as lustrous as polished obsidian. It was now nearly twice as dense as when it began, and it had lost most of the moisture trapped in its bituminous molecules. The bitumens themselves, along with resins and other hydrocarbons, had moved out of the coal layer along fractures and bedding planes.

But chemically it had been altered, too. While the relative amounts of carbon had risen, the absolute amounts of oxygen and hydrogen had decreased. While the oxygen had been driven off slowly and steadily until the coal neared bituminous rank, hydrogen had followed the same pattern until the total carbon in the coal reached about 89%, then hydrogen evolved out of the coal bed very quickly.

The analysis that shows the amounts of elemental constituents in coal is called Ultimate Analysis. Classification through this technique has produced a series of developmental lines that show the significance of relative amounts of carbon, oxygen, and hydrogen in mature coals.

Table 5, derived from Moore (1940), outlines some of those relationships according to coal ranks.

TABLE 5. ULTIMATE ANALYSIS OF PEAT AND COALS

Fuel*	% Hydrogen	% Carbon	% Nitrogen	% Oxygen	Heat Value (Btu/lb)
Peat	8.33	21.03	1.10	62.91	3,600
Lignite	6.60	42.40	0.57	42.13	7,100
Subbituminous	6.14	55.28	1.07	33.90	9,300
Ash and moisture-free	4.74	76.28	1.47	17.01	13,000
Bituminous	5.24	78.00	1.23	7.47	13,900
Ash and moisture-free	5.39	87.00	1.37	5.18	15,500
Low volume bituminous	4.14	79.97	1.26	4.18	14,000
Ash and moisture-free	4.37	89.07	1.40	2.64	15,700
Semi-anthracite	3.58	78.43	1.00	4.86	13,200
Ash and moisture-free	3.76	92.15	1.18	2.17	15,500
Anthracite	1.89	84.36	0.63	4.40	13,300
Ash and moisture-free	1.77	94.39	0.71	2.13	14,900

*On an as-received basis, except where specified ash and moisture-free.

Data from Moore, E.S., 1940.

Figures 4 and 5 show relationships between carbon and oxygen and carbon and hydrogen in a large sampling of coal ranks.

TRACE ELEMENTS AND INORGANIC CONSTITUENTS IN COAL

Coal is comprised chiefly of organic compounds, but all coals, regardless of rank or type, include inorganic ingredients as well. Because of the varieties of depositional environments and the complex formative processes that create coal, virtually every element in nature can be found in coal (National Research Council 1980). Most of the inorganic components are of little concern since they do not alter the technological performance of the fuel nor create imminent health or environmental hazards. But some elements and compounds, because of their toxicity, biological effects, and tendencies to concentrate in certain coals, are of great concern at every step in the fuel cycle.

The elements of greatest concern in coals are sulfur, arsenic, boron, cadmium, lead, mercury, molybdenum, and selenium (National Research Council 1980). They are especially troublesome since they are all potentially toxic and tend to accumulate in coals at greater concentrations than those found in the earth's crust. Five other elements, radon, radium, uranium, thorium, and polonium, are also of special concern since they are all radionuclides that are sometimes found in coals. One of them, uranium, is encountered in some U.S. coals at levels far above the average levels in the earth's crust. Its potential biological effects, though slight, must be considered before uraniferous coals are used in commercial amounts. Figure 6 shows the elements of primary concern in the coal fuel cycle.

In a broad sense, there are two types of inorganic components found in coals. They are often described as "inherent" and "adventitious." The former includes minerals that were present in coal-forming plants prior to deposition in the bog; the latter refers to inorganic constituents that found their way into the deposit after the death of the plants (Francis 1961). Some inorganic compounds, such as selenium, molybdenum, and sulfur, are both inherent and adventitious in varying degrees. Others are primarily adventitious, since they were transported into the decaying peat by fresh or marine waters and sediments. While adventitious minerals, including some sulfur compounds, can be removed from coal by mechanical cleaning, inherent minerals either volatilize upon combustion or become part of the ash that is destined for recycling or disposal.

The most abundant mineral compounds found in coal are silicates of aluminum, calcium, magnesium, and iron. In Illinois coals, for instance, more than 50% of the ash by weight is comprised of illite, kaolinite, and other mixed-layer clays (Schmidt 1979). Also prevalent in most U.S. coals are sulfides (mainly pyrite) and carbonates such as calcite. The dominant clayey materials appear to have been deposited during the accumulation of organic matter in the bog, while adventitious sulfides and carbonates accumulated subsequent to peat deposition (Schmidt 1979). Silicates and carbonates are sometimes found in sufficient quantities to reduce the quality and thermal efficiency of a given coal, but they are not especially troublesome pollutants from an environmental

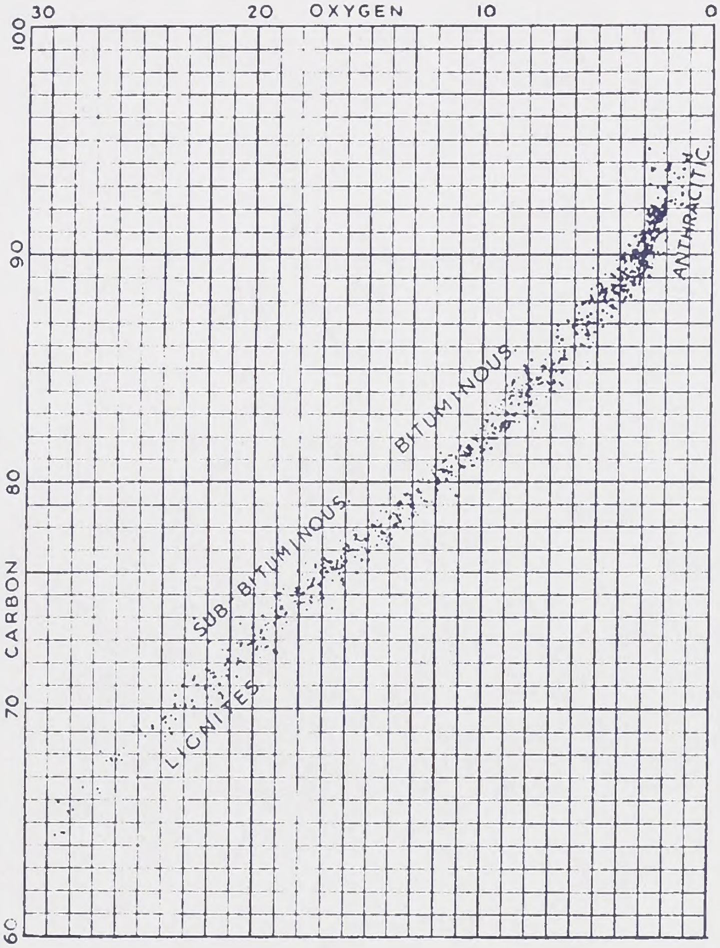

Figure 4.--Variation in the composition of coals from lignites to anthracites, C/O coordinates (Source: Francis 1961).

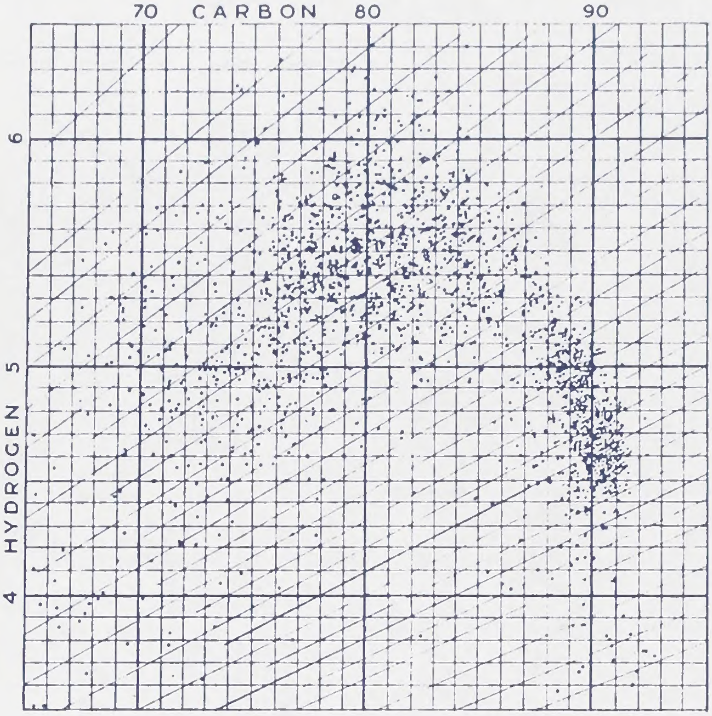

Figure 5.--Ultimate composition of coals, C/H coordinates (Source: Francis 1961).

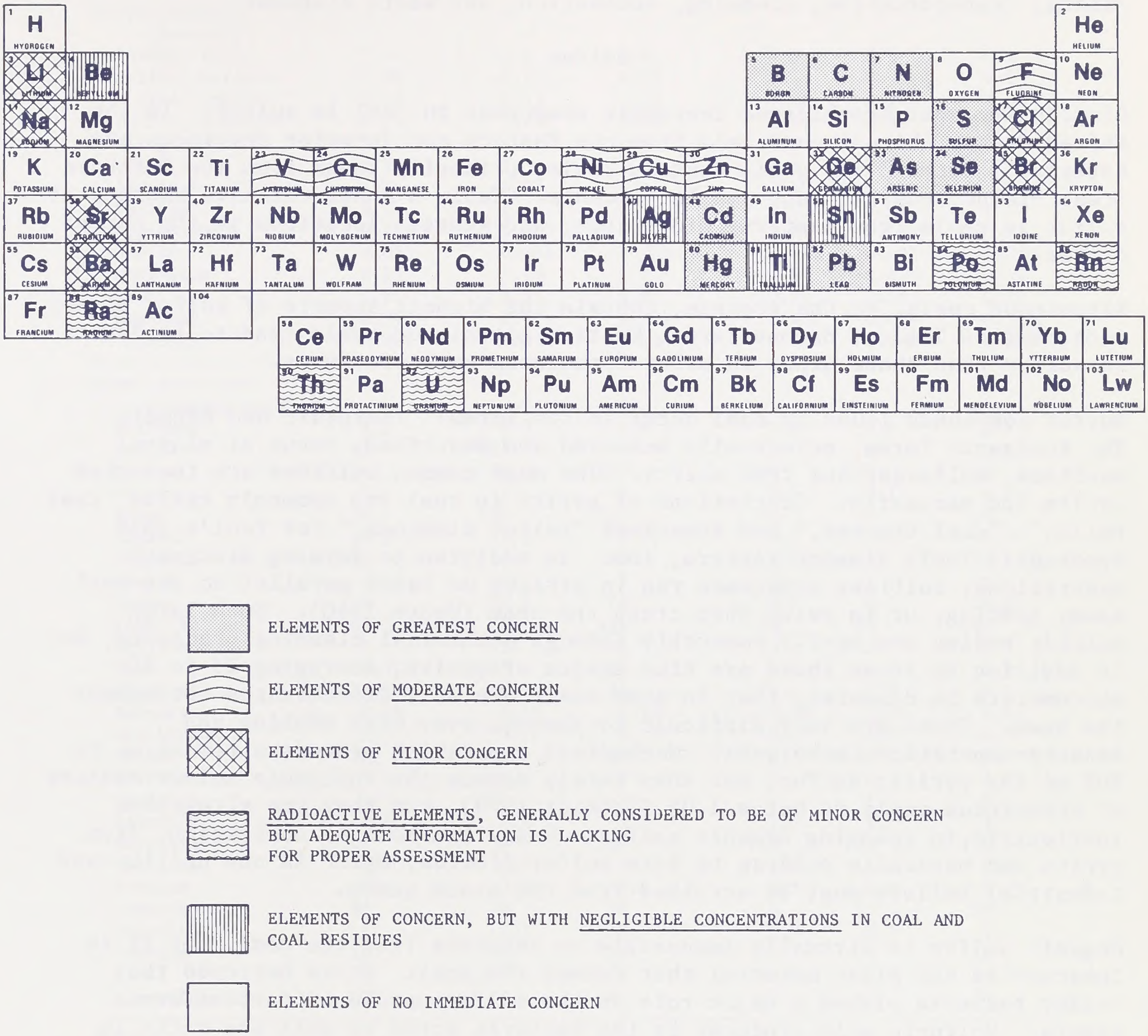

Figure 6. Potentially hazardous elements in coal resource development.

From: National Research Council. 1980. Trace-Element Geochemistry of Coal Resource Development Related to Environmental Quality and Health. Washington, D.C.: National Academy Press, p. 3.

or health standpoint. The sulfides, however, are.

The following discussion identifies three types of inorganic components, sulfur, trace elements, and uranium, that are of special concern in coal mining, transportation, cleaning, combustion, and waste disposal.

Sulfur

Clearly the most troublesome inorganic component in coal is sulfur. In the United States, bituminous coals from the Eastern and Interior Provinces are especially rich in it, while Western coals, primarily those from the Northern Great Plains, contain much smaller amounts. Table 6 shows relative amounts of sulfur in coals from Eastern, Midwestern, and Western locations in the United States.

Bituminous coals, on the average, contain the highest amounts of sulfur of any rank, but as Table 6 demonstrates, Western bituminous coals tend to be lower in sulfur than those mined in other bituminous coal provinces.

Sulfur compounds found in coal occur in two forms: inorganic and organic. The inorganic forms, more easily measured and described, occur as mineral sulfides, sulfates, and free sulfur. The most common sulfides are iron-rich pyrite and marcasite. Concretions of pyrite in coal are commonly called "coal balls," "coal brasses," and sometimes "sulfur diamonds," for fool's gold apparently fools diamond-seekers, too. In addition to forming distinct concretions, sulfides sometimes run in streaks or bands parallel to the coal seam, bedding, or in veins that cross the seam (Moore 1940). Such large sulfide bodies are easily removable through mechanical cleaning processes, but in addition to those there are tiny grains of pyrite, averaging 25 to 40 micrometers in diameter, that in some coals are well disseminated throughout the seam. These are very difficult to remove, even with washing and density-separation techniques. Mechanical separation processes remove up to 50% of the pyritic sulfur, but they rarely reduce the inorganic sulfur content of bituminous coals to below 1.0% (Schmidt 1979), and they are altogether ineffective in removing organic sulfur. Under the heat of combustion, iron pyrite and marcasite oxidize to form sulfur dioxide, which in new utility and industrial boilers must be scrubbed from the stack gases.

Organic sulfur is virtually impossible to separate from the coal, for it is inherent in the plant material that formed the coal. It is believed that sulfur bacteria played a major role in the sulfur uptake of Carboniferous plants. Sulfuric acid produced by the bacteria acted on soil and rocks to produce calcium, magnesium, and potassium sulfates that were then assimilated by Paleozoic plants. The sulfur became part of the plant protein and was in turn deposited in the bog, where it persisted through anaerobic decay. Under conditions produced by extended marine burial, amounts of organic sulfur apparently soar. Some petroleum oils, oil shales, and coals deposited in marine formation contain especially high amounts of organic sulfur (Francis 1961), though the cause of this is unknown. Most of the organic sulfur in coal is found in the woody macerals, although algae-derived, marine boghead

TABLE 6. AVERAGE U.S. COAL COMPOSITION BY LOCATION[1,2]

Element*	Appalachian Region	Interior Province	Gulf Province	Northern Great Plains Province	Rocky Mountain Province	Alaska
Major elements (percent)						
Sulfur, total	2.3	3.9	1.9	1.2	0.6	0.2
Sulfur, sulfate	0.09	0.27	0.33	0.03	0.05	0.01
Sulfur, pyritic	1.56	2.37	0.59	0.76	0.19	0.07
Sulfur, organic	0.74	1.25	0.96	0.37	0.32	0.12
Nitrogen	1.3	1.2	0.4	0.9	1.2	0.7
Silicon	2.7	2	6.6	1.4	2.5	2.9
Aluminum	1.6	0.97	2.1	0.69	1.2	1.5
Calcium	0.12	1.2	1.2	0.97	0.59	1
Magnesium	0.068	0.089	0.291	0.255	0.104	2.5
Sodium	0.032	0.035	0.732	0.182	0.102	0.018
Potassium	0.23	0.16	0.3	0.04	0.076	0.12
Iron	1.9	3.3	2.2	0.75	0.45	0.38
Maganese	0.062	0.014	0.024	0.051	0.036	0.0061
Titanium	0.09	0.052	0.16	0.042	0.061	0.077
Minor and trace elements (ppm)						
Antimony	1.2	1.7	0.9	0.6	0.4	2.7
Arsenic	27	21	6	3	2	3
Barium	100	70	200	500	200	700
Beryllium	2	3	2	0.5	0.7	0.7
Boron	30	100	100	70	70	70
Cadmium	0.7	7.1	1.3	0.2	<0.1	<0.2
Chromium	20	15	20	5	5	15
Cobalt	7	7	7	2	2	5
Copper	24	20.2	28	8.3	9.1	16.8
Fluorine	80	71	124	45	70	90
Gallium	7	5	10	3	3	5
Lead	15.3	55	20	5.3	5.5	5.9
Lithium	27.6	11	28	6.0	9.2	10.1
Mercury	0.24	0.14	0.18	0.09	0.06	4.4
Molybdenum	3	5	3	2	1.5	1.5
Nickel	15	30	20	3	30	10
Niobium	5	1.5	7	5	1	3
Scandium	5	3	7	2	2	5
Selenium	4.7	4.6	7	1.0	1.6	2
Strontium	100	50	200	150	100	100
Thallium	4.9	5.2	8.3	2.7	3.6	4.4
Uranium	1.4	3.3	3.2	0.9	1.6	1.2
Vanadium	20	20	50	10	15	30
Ytterbium	1	0.7	2	0.3	0.5	1
Yttrium	10	10	20	5	5	10
Zinc	20	373	40	25.6	9.9	24
Zirconium	50	15	70	15	20	20

NOTES:

1. From Swanson *et al.* 1976.

2. Sulfur and nitrogen analyses are expressed on an as-received basis. Arsenic, fluorine, mercury, antimony, selemium, thorium, and uranium were determined directly on a whole-coal basis. The remaining elements were determined in the ash and are expressed on a whole-coal basis.

*Average sulfur and nitrogen calculated from analysis of 158, 90, 19, 40, 86, and 9 samples from Appalachian region, Interior Province, Gulf Province, Northern Great Plains Province, Rocky Mountain Province, and Alaska, respectively. Averages of the remainder of the elements were calculated from the analysis of 331, 143, 34, 93, 124, and 18 samples from the Appalachian region, Interior Province, Gulf Province, Northern Great Plains Province, Rocky Mountain Province, and Alaska, respectively.

coals sometimes contain extraordinary amounts of organic sulfur.

While inorganic sulfur commonly occurs in amounts between 0.50% and 3.5%, organic sulfur ranges between 0.5% and 2.0% in bituminous coals. High concentrations of each can produce environmental hazards along the entire coal fuel cycle, but inorganic sulfur owns the more dramatic history of effects. Acid mine drainage, a familiar problem in Eastern and Interior Province mining districts, is the result of sulfuric acid mobilization in high-sulfur coals. Prior to 1977, over 200,000 acres of land were rendered barren by acid mine drainage, and some 10,500 miles of waterways were degraded (National Research Council 1980). The areas most affected were those where mining was most extensive and pyritic materials in coals were most abundantly exposed to oxidation. A secondary effect to acid mine drainage was the mobilization and concentration of other trace materials in coal and surrounding soils by the sulfuric acid. The extent and effects of these concentrations are poorly documented, but the redistribution of trace elements remains a concern in regard to the transportation, storage, and handling of all high-sulfur coals (National Research Council 1980). Methods of treatment used to prevent acid mine drainage are now prescribed in the Surface Mining Control and Reclamation Act of 1977, which prohibits the discharge of acidic waters from mines and spoils areas. Methods that eliminate the mobilization of trace elements usually involve neutralization of wastewater with alkaline agents.

The escape into the atmosphere of sulfur dioxide and the potential for acid rain formation are clearly the greatest environmental concerns with regard to sulfur in coal. Both organic and inorganic sulfur produce this pollutant, which can be reduced by more than 90% with existing flue-gas desulfurization systems. Advanced coal cleaning techniques might ultimately be more effective in removing sulfur prior to coal combustion, but as discussed above, current cleaning techniques rarely reduce sulfur in coal to below 1%. Only about half of the coal now consumed in the U.S. is cleaned, and the trend away from cleaning has been very pronounced since the mid-1960s (Schmidt 1979). It is thus clear that flue gas treatment will continue to carry the load in reducing hazardous sulfur emissions from coal until new combustion technologies, such as fluidized bed, are available commercially.

Trace Elements

Western coals are not only lower in sulfur than other U.S. coals, but they are also lower in trace element concentrations. Nevertheless, they, too, must be treated carefully from the mine to the ash-pile in order to reduce the potential for the release of toxic materials.

Of greatest concern in all U.S. coals are above-background concentrations of boron, arsenic, cadmium, lead, mercury, molybdenum, and selenium. Four of those--arsenic, lead, mercury, and cadmium--are toxic to most biological systems above specified levels. Any coal mining or conversion activities that tend to concentrate these trace elements must be monitored with caution. The remaining elements are of greatest concern in regard to their tendencies to accumulate in plant tissue in concentrations that are harmful to livestock and wildlife (National Research Council 1980).

These seven elements tend to concentrate in coal at levels above those found in the earth's crust, but it is very rare to find alarmingly high levels of any of them in coals. Of greater concern is the gradual accumulation of one or more of them in biological systems through normal mining, handling, and transportation, and the mobilization of these and other potentialy harmful elements in the fly ash emitted from coal boilers.

Current annual production of captured fly ash at electric utility stations in the United States is 56 million tons. Since utilities consume about two-thirds of U.S. coal, it must be assumed that coking and industrial boiler applications contribute significant amounts of fly ash. Only 15% of the ash captured at utility boilers is used in industrial applications. Of the remainder, 36% is trucked to landfills, while the rest is sluiced away into disposal ponds. Coal ash contains concentrated trace materials from coal. What doesn't get trapped in baghouses or precipitators and properly disposed of wafts out into the air, where minute particles can remain airborne for months or combine with sulfurous gases and reenter the biosphere. Some of the particles are of the sizes (<0.5 um) that tend to lodge in the lung and possibly create chronic health problems for people and animals. At the concentrated ash-fills that result from disposal, methods must be employed to minimize seepage of toxic elements into ground and surface waters, and airborne particulate abatement techniques must be employed to minimize dust emissions.

Table 7 summarizes the sulfur and trace element contents of U.S. coals by rank. Table 6 summarizes them by geographical region.

Uranium

Uranium-bearing coals present problems of a special, though minor, kind. In 97% of U.S. coals, uranium is present in concentrations at or below levels found in the earth's crust (National Research Council 1980), about 2 ppm. Most of the trace amount of uranium in steam coals ends up in the bottom ash during combustion, since uranium is so heavy an element, but trace amounts of ^{238}U as well as radon, thorium, and radium can be carried up the stack attached to other fine particles. One electrical power plant, the Jim Bridger Station at Rock Springs, Wyoming, is reported to emit detectable levels of radionuclides from the stack. Their effect has not been thoroughly assessed.

Uranium and other radionuclides in coal are of concern because of their potential carcinogenic and toxic effects. It is known that radioactive isotopes of thorium and radon and their decay "daughters," polonium, bismuth, and lead, can cause lung cancer. Chronic exposure to low-level radiation from uranium is also suspected of producing health effects, though threshold levels, if they exist, have not been determined.

Uraniferous coals can be found in three areas of the United States. In the north-central Midcontinent a high-sulfur bituminous coal of Pennsylvanian age contains uranium at concentrations of 10 to 15 ppm (National Research Council

TABLE 7. CHEMICAL COMPOSITION OF U.S. COALS^{1,2}

Element	Anthracite	Bituminous	Sub-butuminous	Lignite	Average^{3}	Estimated Worldwide Average
Major elements (percent)						
Sulfur (S), total	0.8	2.7	0.7	1.7	2.0	2.0
Sulfur (S), sulfate	0.02	0.16	0.04	0.24	0.12	--
Sulfur (S), pyritic	0.35	1.70	0.36	0.68	1.19	--
Sulfur (S), organic	0.48	0.88	0.32	0.75	0.70	--
Phosphorus (P)	--	--	0.10	0.007	--	0.05
Silicon (Si)	2.7	2.6	2.0	4.9	2.6	2.8
Aluminum (Al)	2.0	1.4	1.0	1.6	1.4	1.0
Calcium (Ca)	0.07	0.33	0.78	1.2	0.54	1.0
Magnesium (Mg)	0.00	0.08	0.18	0.31	0.12	0.02
Sodium (Na)	0.05	0.04	0.10	0.21	0.06	0.02
Potassium (K)	0.24	0.21	0.06	0.20	0.18	0.01
Iron (Fe)	0.44	2.2	0.52	2.0	1.6	1.0
Manganese (Mn)	0.002	0.01	0.006	0.015	0.01	0.005
Titanium (Ti)	0.15	0.08	0.05	0.12	0.08	0.05
Minor and trace elements (ppm)						
Antimony (Sb)	0.9	1.4	0.7	0.7	1.1	3.0
Arsenic (As)	6	25	3	6	15	5.0
Barium (Ba)	100	100	300	300	150	500
Beryllium (Be)	1.5	2.0	0.7	2.0	2.0	3
Bismuth (Bi)	--	--	<0.6	<0.8	<0.7	5.5
Boron (B)	10	50	70	100	50	75
Bromine (Br)	--	--	2.3	3.2	2.6	--
Cadmium (Cd)	0.3	1.6	0.2	1.0	1.3	--
Cerium (Ce)	--	--	5.5	12.3	7.7	11.5
Cesium (Cs)	--	--	0.40	0.25	0.4	--
Chlorine (Cl)	--	--	255	110	207	1000
Chromium (Cr)	20	15	7	20	15	10
Cobalt (Co)	7	7	2	5	7	5
Copper (Cu)	27	22	10	20	19	15
Dysprosium (Dy)	--	--	2.7	1.4	2.2	--
Erbium (Er)	--	--	0.46	0.16	0.34	0.6
Europium (Eu)	--	--	0.61	0.13	0.45	0.7
Fluorine (F)	61	77	63	94	74	--
Gadolinium (Gd)	--	--	0.13	0.21	0.17	1.6
Gallium (Ga)	7	7	3	7	7	7
Germanium (Ge)	--	--	0.47	1.20	0.71	5
Hafnium (Hf)	--	--	0.75	0.30	0.60	--
Holmium (Ho)	--	--	0.13	0.06	0.11	0.3
Iodine (I)	--	--	1.0	1.3	1.10	--
Lanthanum (La)	--	--	7.5	3.2	6.1	10
Lead (Pb)	10	22	5	14	16	25
Lithium (Li)	33	23	7	19	20	65
Lutetium (Lu)	--	--	0.09	0.05	0.08	0.07
Mercury (Hg)	0.15	0.20	0.12	0.16	0.18	0.012
Molybdenum (Mo)	2	3	1.5	2	3	5
Neodymium (Nd)	--	--	50	11	37	4.7
Nickel (Ni)	20	20	5	15	15	15
Niobium (Nb)	--	--	5.4	2.7	4.5	--
Praseodymium (Pr)	--	--	6.1	2.7	2.7	2.2
Rubidium (Rb)	--	--	5.3	0.98	2.90	100
Samarium (Sm)	--	--	0.50	0.27	0.42	1.6
Scandium (Sc)	5	3	2	5	3	5
Selenium (Se)	3.5	4.6	1.3	5.3	4.1	3
Silver (Ag)	--	--	0.17	0.26	0.20	0.50
Strontium (Sr)	100	100	100	300	100	500
Tellurium (Te)	--	--	0.1	0.1	0.1	--
Terbium (Tb)	--	--	0.1	0.1	0.1	0.3
Thallium (Tl)	--	--	0.1	0.12	0.1	--
Thorium (Th)	--	--	2.3	1.2	1.9	--
Thulium (Tm)	--	--	0.07	0.07	0.07	--
Tin (Sn)	--	--	1.7	1.3	1.6	--
Tungsten (W)	--	--	2.2	3.3	2.5	--
Uranium (U)	1.5	1.9	1.3	2.5	1.6	1.0
Vanadium (V)	20	20	15	30	20	25
Ytterbium (Yb)	1	1	0.5	1.5	1	0.5
Yttrium (Y)	10	10	5	15	10	10
Zinc (Zn)	16	53	19	30	39	50
Zirconium (Zr)	50	30	20	50	30	--

NOTES:

1. Data from Swanson, V.E., et al. 1976.

2. Dashes indicate no data included in source.

3. Except for sulfur, the average composition of U.S. coals was calculated from the analysis of 53, 509, 183, and 54 samples of anthracite, bituminous, subbituminous, and lignite, respectively; the all-coal average is calculated from analysis of 799 samples. The average sulfur was calculated from the analysis of 38, 277, 105, and 26 samples of these coals, respectively. The all-coal average sulfur is from the analysis of 488 samples. See footnotes to Table 8 for methods used for determining mean concentrations.

1980). The coal is used at a few power stations in Missouri and southern Iowa. The Black Butte coals mined near Rock Springs and an unmined deposit in the Red Desert of the Wyoming Basin near Rawlins also contain significant amounts of uranium. It is the former coal that apparently causes the radionuclide emissions from the Jim Bridger Station. Finally, a uraniferous lignite deposit found in the northwestern corner of South Dakota contains uranium in high enough concentrations (up to 100 ppm) that it was once mined and burned so that uranium could be extracted from the ash (National Research Council 1980). The process proved uneconomical and was soon abandoned.

During coal usage, radionuclides are emitted in infinitesimal amounts and are not considered a hazard. The National Research Council Committee on Trace Element Geochemistry of Coal Resource Development, however, has recommended more study to augment the shallow data base on radionuclides in coal.

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THE FORT UNION FORMATION IN MONTANA

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THE FORT UNION FORMATION IN MONTANA

INTRODUCTION

Coal-bearing Fort Union rocks cover an extensive area of eastern Montana, from the Wyoming state line southwest of Billings in Big Horn County generally north to the Canadian border in Valley County. In the southwestern portion of the Fort Union Region, coals of subbituminous rank occur along the northern part of the Powder River Basin, west of a line through Powder River, Custer, northeastern Rosebud, and southeastern Garfield Counties. To the east of this line at the western portion of the Williston Basin, the coals are of lower rank or lignitic. The great extent of this coal region can be seen in the number of named coal fields recognized by the Montana Bureau of Mines and Geology in a recent publication, as also reproduced in the Keystone Coal Industry Manual (McGraw-Hill Mining Publications 1981). Listed in this report are 62 named coal fields, covering 1,340,000 acres, with an estimated reserve of over 50 billion tons. In Montana the Fort Union Formation is underlain by Upper Cretaceous rocks of the Hell Creek Formation and overlain by the Eocene Wasatch Formation. Contacts between these formations are not always distinct in the field; however, in Montana the coal associated with this rock sequence occurs mainly in the upper member (Tongue River) of the Fort Union. Within Montana, the strata now incuded in the Fort Union Formation were laid down along a large low-lying plain, extending from the early Laramide highlands on the west to the margins of the Cannonball Sea to the east in present-day North Dakota (Fig. 1).

ORIGINS AND DEPOSITION

In the late Cretaceous (Maestrichian), the sea which had occupied much of the western interior region of the United States began its final regression to the east, where marine conditions remained into the Paleocene in the Dakotas (Curry 1971). Associated with this withdrawal are the Lewis Shale, the Fox Hills Sandstone, and equivalent deposits; these are the latest marine Cretaceous rocks in the western interior. This last submergence of the area in the Powder River Basin possibly reached its greatest extent about 80 million years ago (McGraw 1971), a period which also began the great sequence of mountain building and uplift which created the beginnings of the Laramide orogeny.

As the sea retreated to the east, uplift of the western mountain regions began to appear. Between these areas of uplift and the sea margin, the old sea bed remained a relatively flat, near-sea-level coastal plain, heavily vegetated and dissected by an array of large and small streams which carried sediment from the newly emergent sources across the plain and eventually to the sea--deposits which today represent the Hell Creek Formation. At the end of the Cretaceous, structural movement of the Laramide orogeny created the beginnings of the depositional basin--now the Powder River Basin--extending from southeastern Wyoming into Montana. Ultimately, subsidence in the basin and filling due to erosion from the west and east would lead to accumulation of a maximum of 8,000 feet of sedimentary rock (Curry 1971).

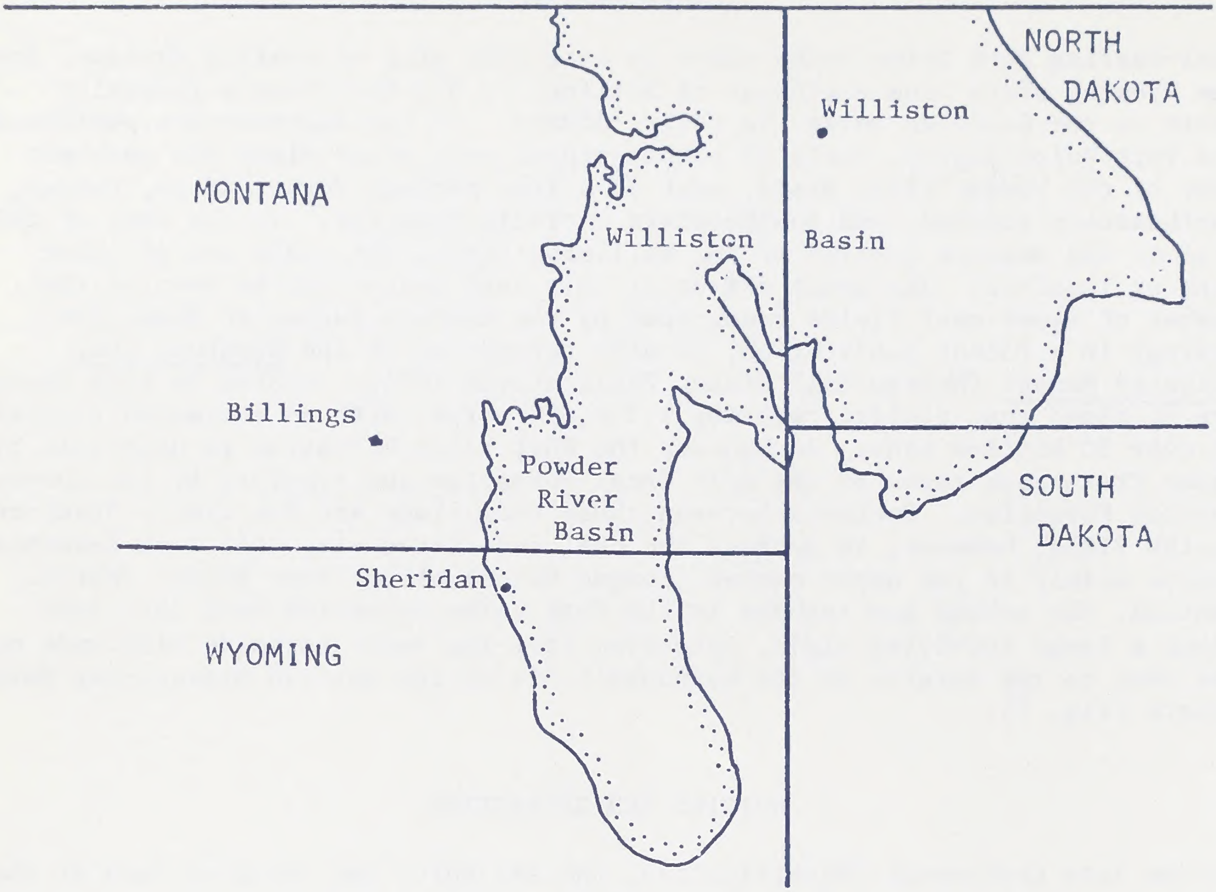

Figure 1. Area of Fort Union Formation (after Matson and Pinchock 1977).

In Wyoming, the Laramie Mountains began to emerge. To the west, the northern Big Horn Mountains became a source of sediment. In the east, the Black Hills area emerged and contributed to the eventual filling of the Powder River Basin and the Williston Basin to the north in Montana and North Dakota (Curry 1971, McGraw 1971). These areas around the basins of deposition had become established by the Cretaceous-Paleocene transition. The Powder River Basin is not symmetric; its axis lies well to the west of its geographic center.

The distinction between the older Cretaceous rocks and the Paleocene is not a clearly defined break in rocky type nor is the Cretaceous bounded by any unconformity indicating an episode of nondeposition across the entire area from Wyoming through Montana into North Dakota. Instead, the contact between the Cretaceous and Tertiary has been defined on the basis of its flora, fauna, and the beginning of coal deposition. This "boundary problem" has occupied many geologists for over 100 years. The most accepted method of determining the transition from the Hell Creek to the lower (Tullock) Fort Union Formation has been based on the occurrence of dinosaur fossil remains and the first coal or lignite zone (Brown 1962, Matson and Blumer 1973).

Across the wide, heavily vegetated plains, the last representatives of the typical dinosaurs who had been the dominant large animals since the early Mesozoic roamed. Hell Creek beds are defined as those lying below the first coal zone and containing the fossilized remnants of these last creatures (Brown 1962). The deposition of lignite at the base of the Fort Union Formation represents the resumption of peat accumulation after a long interval of coal-barren strata across Wyoming, Montana, and into North Dakota. This event, while seemingly instantaneous from a modern perspective, probably occupied a considerable interval of geologic time. The change from the Late Cretaceous also represents the beginning of a change from low floodplains to a distinctly swampier environment in which peat accumulation became widespread and common. In areas where the basal lignite zone does not exist, floral and faunal elements correlated to strata above and below the coal can be used to determine the boundary between Cretaceous and Paleocene strata (Brown 1962). During the Paleocene, while the rocks and coal beds of the Fort Union Formation were being deposited, swampy conditions existed over the entire area from west to east in Montana. Fort Union rocks are present from the Livingston area on the west across the plains and into the marine strata of the Cannonball Sea in central North Dakota.

Lowest strata of the Fort Union Formation in Montana are dominated by sandstone, siltstone, and shales. In the Powder River Basin, numerous lenticular lignite beds occur as well (Matson and Blumer 1973). The strata were probably deposited as the areas dominated by swamp-dwelling plants grew and as enlarged environments favorable for preservation occurred due to subsidence and flooding.

Brown (1962) suggested the Dismal Swamp of Virginia and North Carolina as a modern analog of the conditions favorable for this type of peat accumulation. This swamp is similar in origin but much smaller than the area occupied by the Fort Union swamps. From the highland sources of sediment and the origin of the streams which carried these sediments, the terrain sloped gently into the basins. This upland piedmont area was the major region of deposition of coarser erosional detritus. Even this drier or better drained area was most likely covered by heavy vegetation, and in many strata this is confirmed by the remains of plant material. To the east, the land quickly became very low with only a slight slope toward the sea margin. Across this plain, streams passed slowly and with an increasingly finer grained sediment load, as reflected in the finer silts and shales deposited there.

Within an area such as this, the dominant force for determining the distribution of sediments was the location of the rivers and their associated structures. Large river channels have a number of distinctive features which determine the geometry of the swamp and the resulting peat accumulations and ultimately the coal distribution. Usually a river flowing across a flat plain will be surrounded on both sides by a natural levee where it flows during normal runoff periods. Beyond the levee, there may be a broad expanse of alluvium, poorly drained and swampy, which has a dense cover of vegetation. The nature of the vegetative cover will vary, depending upon the climate and nature of the alluvial substrata in which it is rooted, but under warmer climatic regimes, these backswamp regions are areas of extremely high production of vegetative material. Peat accumulation in these swamps depends upon the proper conditions for its preservation. Burial following accumulation may lead ultimately to coal production. Beyond the backswamp floodplains, higher ground occurs where vegetation may cover the surface. But usually due to these areas being beyond the reach of all but the most severe floods, decay proceeds more rapidly and peat accumulations are small. When a low-lying area as large as that under consideration in the Fort Union occurs, the extent of the backswamps and lake-dominated depositional areas becomes enormous.

With this basic model in mind, it becomes clear that, during the depositional cycle related to coal bed or seam formation, the peat accumulation process continues under a heavy growth of plants, with almost immediate peat burial under fallen plant parts for long time periods. This continual deposition of peat under conditions which stall or entirely preclude decay allows great depths of peat to accumulate over a large area. Occasionally, as in present times, high water conditions in the river's watershed would increase flow to the extent necessary to force a breech in the levees bounding the normal river channel. The resultant flooding of the adjacent lowland would carry a very heavy load of waterborne sediment out over the peat deposits and their burial would be complete. These episodes of flooding may result in thin shale streaks or parting in coal seams. If, however, the flooding resulted in permanent alterations in the stream channel morphology, long sequences of deposition of sand, silt, and shale result. These depositional sequences serve as major splits or long periods of non-deposit of coal.

The duration of individual events in this cyclic sequence is irregular, indicated by the broad variation in the present disposition of coal seams in the Fort Union.

The Fort Union Formation coals and lignites were deposited on a large, low-lying plain in an environment conducive to high sustained yields of plant growth. This environment was geographically dominated by large rivers bearing sediments from highlands to the west, south, and southeast into two large basins, the Powder River Basin on the southwest and the Williston Basin to the north and east. Periodic subsidence, flooding, and changes in channel morphology influenced the thickness and lateral extent of the sedimentary rocks and coal seams across Montana (Figs. 1 and 2).

STRATIGRAPHY

As stated above, the Paleocene Fort Union Formation is best separated by its faunal content from the Upper Cretaceous rocks below it (Brown 1962). The distinct faunas (dinosaurs below the contact and mammals above) are a consistent indication of the evolutionary change which occurred between the Mesozoic and Tertiary. In areas where it exists, the lowest lignite or coal bed above the last dinosaur remains is used to mark the boundary of the lowest Fort Union sediments.

In Montana the Fort Union Formation is divided into three named subunits or members, the Tongue River, Lebo, and Tullock, the lowest member which extends from the base of the lowest coal bed to the base of the Big Dirty Coal Bed. In the Powder River Basin, the Tullock Member is reported to be between 275 and 500 feet thick. A color change between the Hell Creek and Tullock Member has been used in some areas as an indication of the boundary of the Fort Union Formation (Matson and Pinchock 1977). This distinction is based on the alteration of dark- and light-colored sediments, the sequence being as follows: Tongue River--light; Lebo--dark; Tullock--light; Hell Creek--dark (Fig. 3).

Since this color distinction feature is not found at all localities and becomes increasingly vague east of Miles City, it is only a secondary method of separating the Fort Union from the Hell Creek and determining the boundaries of the members of the Fort Union itself (Brown 1962, Matson and Pinchock 1977). Above the Tullock in the Powder River Basin lies the Lebo Member, which is determined as beginning at the base of the Big Dirty Coal Bed. In this area, the Lebo is reported as varying in thickness from 300 to 600 feet and is the member that comprises the dark series of rocks between the lighter Tullock and Tongue River Members. The uppermost member of the Fort Union Formation is the Tongue River, which contains most of the strippable coal seams in Montana, Wyoming, and North Dakota. The Tongue River Member extends to the top of the Roland Coal Bed and is reported to be from 1,200 to 1,700 feet thick in southern Montana (Matson and Blumer 1973).

In summary, the Fort Union Formation as it appears in the Powder River Basin in southeastern Montana ranges in three defined members from about 1,800 to 2,500 feet in thickness. Coal occurs in all the members, but the majority of the strippable coal occurs in the upper 1,700 feet in the Tongue River Member (Matson and Blumer 1973, Matson and Pinchock 1977).

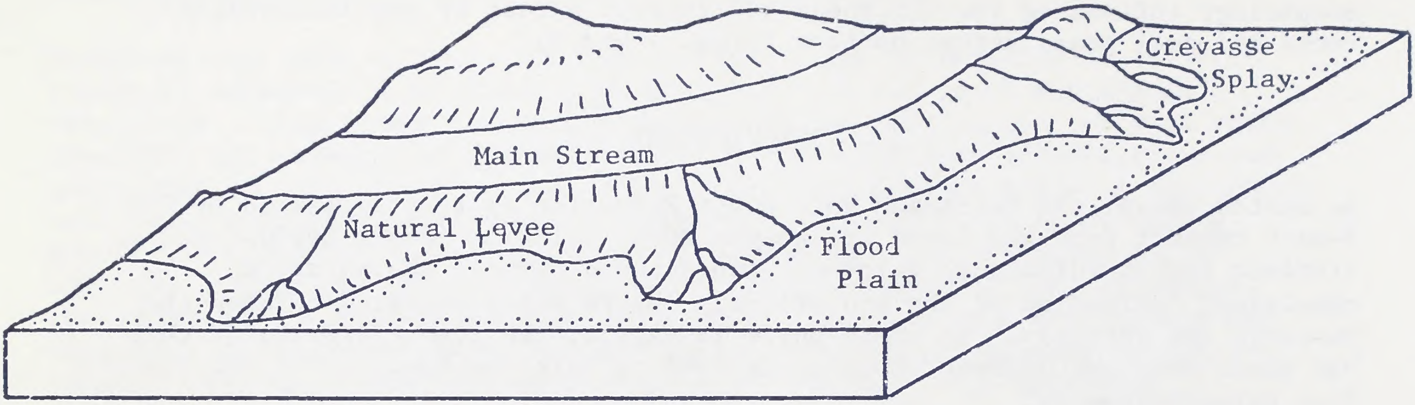

Figure 2. Alluvial plain depositional environments (after Jacob 1972).

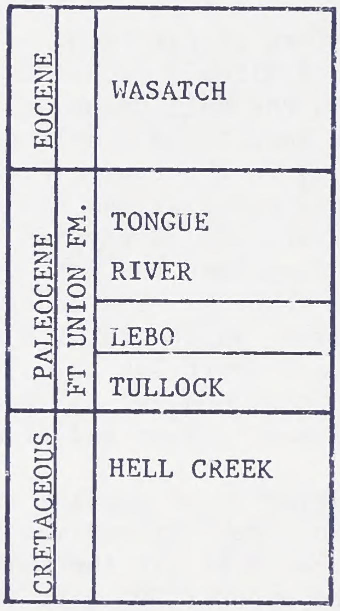

Figure 3. Generalized stratigraphic column of the Fort Union Formation of southeastern Montana.

Eastward from the Powder River Basin, distinctions between the members of the Fort Union Formation decrease, and the Lower Tullock and Lebo are combined into the Ludlow Member in western North Dakota (Matson and Pinchock 1977). The upper Tongue River Member is retained and becomes elevated to formational status in North Dakota where it is, as in Montana, the major lignite-bearing formation (Jacob 1972, Royse 1972).

The Tullock Member in Montana is composed of generally lighter colored sandstone, siltstone, shales, carbonaceous shales, mudstones, and thin coal beds. The original locality from which it was described is Tullock Creek (Rogers and Lee 1923). A sand and siltstone layer at the top of the Tullock is used as a marker for its contact with the overlying Lebo Member. This unit is visible over much of the western area as a resistant, cliff-forming unit which contrasts to the overlying easily eroded Lebo Shales (Matson and Pinchock 1977). As recorded by Matson and Blumer (1973), the Tullock Member at its type locality is 270 feet thick and throughout the Powder River Basin it varies from 270 to 500 feet in thickness. Eastward the upper resistant layer disappears and the distinction between members is locally difficult to define. This lower member most likely was deposited in a coastal plain environment. The overall appearance is that of a drier climate and greater relief than that associated with the accumulation of thick coal seams in backswamp areas. The presence of thin coal seams indicated that at times conditions were locally favorable for peat accumulation, but these conditions did not persist for periods long enough to accumulate to greater thicknesses. Subsidence and burial probably took place in cyclic sequences where decay was rapid and plant growth low, and subsequently the coal seams are thin and widely scattered.

Over the Tullock Member in the west lies the clearly defined Lebo Member, which has its lower boundary placed at the base of the Big Dirty Coal Bed (Matson and Pinchock 1977). Some authors have, however, suggested that the sandstone unit below the Big Dirty would form a better boundary (Garrett 1963, Gerhard 1967). As mentioned, this distinction between the Tullock and Lebo Members disappears to the east of Miles City and in western North Dakota. The lower member of the Fort Union is known as the Ludlow Formation.

Gerhard (1967) in eastern Montana recognized, in the deposition of the Lebo Member, three large cycles, which are related to the energy in the environment of deposition. Each cycle began with an increased energy regime which resulted in a light-colored siltstone deposit followed by clay, shale, then lignite, with a limestone unit near the top. This sequence, with its coarse sediment at the base and finer above, would indicate in the sediment source area a series of changes which were reflected in the type and amount of sediment carried eastward. In keeping with the earlier postulated model of a fluvial-dominated environment of deposition, the lignite, shale, and limestones at the end of each cycle may be the lateral equivalents of backswamp, mudflat or floodplain, and lake deposits. Each of these types coexists in the model. An increased sediment size at the top of each cycle may also indicate an increased amount of uplift and more erosion in the sediment source area (Gerhard 1967). Near Terry, one of these cycles of deposition was measured at 130 feet with a varying thickness depending upon the depth of the channeled upper surface (Gerhard 1967). Channels, with their characteristic sandstone fill structures, were chosen to mark the boundaries of the sedimentary cycles.

Gerhard (1967) also described the lateral variation in thickness and character between lignite beds and limestones. In one section, a 12-foot-thick lignite bed varied laterally through impure lignite to lignitic shale only 2 feet thick in one-half mile (Gerhard 1967). In other cases, the lateral variation sequence may be extended from lignite through shale to a dense limestone. Such variability is in accord with the fluvial deposition model. At the boundary between the Lebo and the overlying Tongue River Member, the only generally accepted marker is the change in color across the contact. Lighter Tongue River rocks contrast with the darker Lebo Member. It has been determined, based upon this color change, that the Lebo thins to the east toward Terry (Matson and Pinchock 1977, Garrett 1963). Even farther east, the Lebo grades into the Ludlow of North Dakota.

At the top of the Fort Union lies 1,200 to 1,700 feet of coal or lignite, shale, clays, and sandstones. It is in this member that the major mineable coal seams in Montana, Wyoming, and North Dakota are found (Matson and Pinchock 1977, Matson and Blumer 1973, Brown 1962). In southeastern Montana in a 1,400-foot section, seven major coal seams totalling 200 feet have been recorded (Matson and Pinchock 1977). The sequence was measured as follows: Three-hundred fifty feet above the Lebo contact lies the 20-foot-thick Rosebud seam, which is separated from the next higher Knobloch seam (40 feet thick) by 60 to 80 feet. Above this seam are 350 to 400 feet of barren rock followed by the 50-foot-thick Wall Bed; 200 feet of rock, then the 20-foot-thick Canyon Bed; and 200 feet of rock, then Dietz No. 1 and No. 2 beds, which may not be distinct or may be two 20-foot-thick beds separated by 50 feet of parting. Above the Dietz Bed, there may be a 250-foot barren interval followed by the 30-foot-thick Anderson Bed, or the Dietz and Anderson Beds may not be distinguishable (Matson and Pinchock 1977; see also Fig. 4.)

Identifiable cycles of deposition have also been recognized in the Tongue River of North Dakota (Jacob 1973). The sequence of these cycles is a basal siltstone or claystone, lignite, siltstone and sandstone, and calcareous sandstone (Jacob 1973). Lignites in this sequence were laid down over the silt and clay layers in backswamps on a river floodplain. The upper sand and siltstones were possibly deposited on the natural levees and crevasse splays. Some of the higher sandstone units may represent river bars (Jacob 1973). This sequence is based on interpretations of the ancient deposits in terms of a low area transversed by a slow nonbraided stream. In North Dakota, the sequence was related to a delta (Jacob 1973). The delta interpretation may not be readily applicable to the Montana portion of the Tongue River Member, but they are similar in nature.

In Montana, Bryson and Bass (1973) interpreted a cyclic deposition in the Moorhead Coal Field as a coastal swamp which underwent periodic subsidence and inundation or increased sediment transport from the west. Also in North

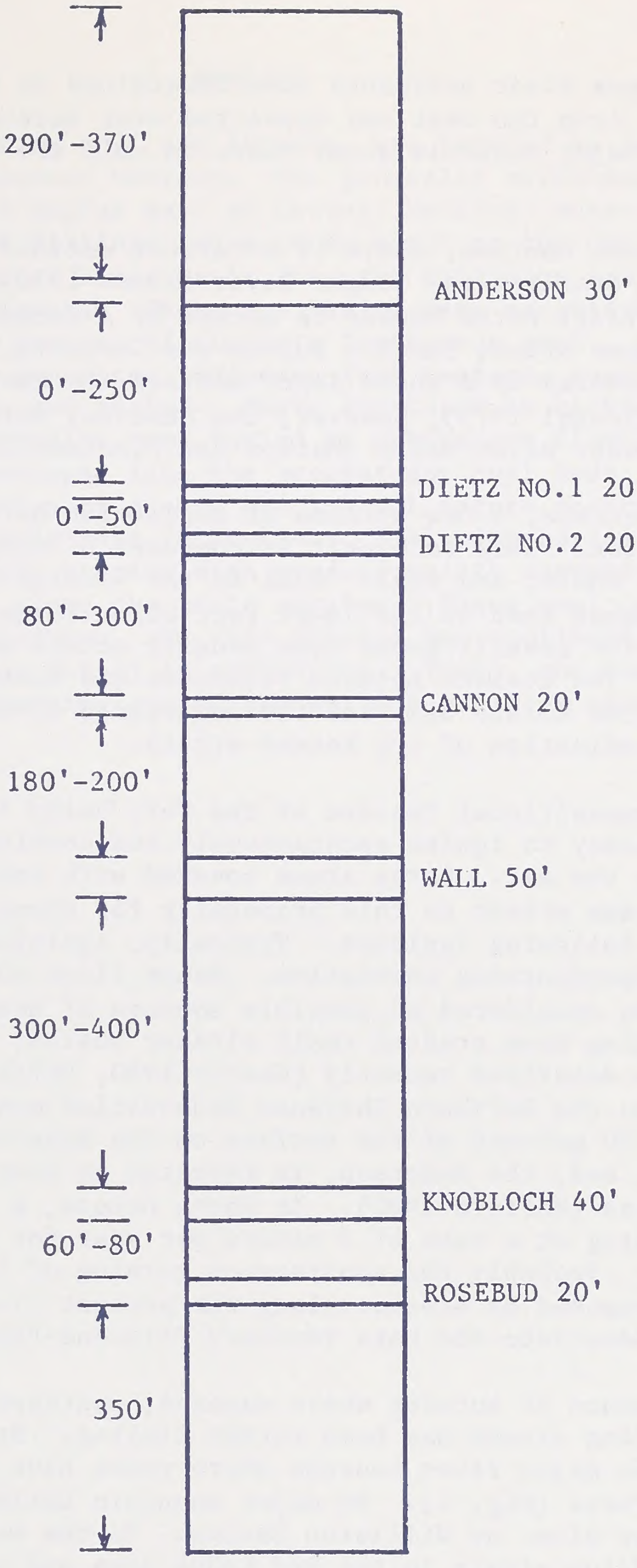

Figure 4. Stratigraphic relationships of important coal beds of the Tongue River Member, southeastern Montana (after Matson and Pinchock 1977).

Dakota, the upper Tongue River sediments were determined by Royse (1970) to have been transported from the west and deposited over backswamp-generated peat accumulations. Major channels occur there in only the basal Tongue River rocks.

In some areas of eastern Montana, there is a further defined member, the Sentinel Butte, which overlies the Tongue River (Royse 1970). The onset of deposition in the Sentinel Butte Member is marked by a sandstone unit (Royse 1970). However, in some areas, Pumpkin Buttes and Coalwood, the Sentinel Butte Member is represented by a shale layer between the Mackin-Walker and Stump Coal Beds (Carmichael 1975); however, the Sentinel Butte Member is not represented in the Powder River Basin (Matson and Pinchock 1977).

At the end of the Paleocene, a new episode of deposition marks the beginning of the Wasatch Formation. This rock unit is composed of conglomerate, sandstone, claystone, shale, and coal. Coal in the Wasatch Formation is, however, much less common than in the lower Fort Union Formation (Matson and Pinchock 1977). A thick fossiliferous zone usually occurs about 30 feet above the Roland Coal Bed. The contact between Paleocene and Eocene is usually placed at the top of the Roland Bed, and the occurrence of the fossil zone above that is clear indication of the Eocene strata.

The most important compositional feature of the Fort Union Formation coals stems from their tendency to ignite spontaneously and continue to burn following exposure to the air. Large areas covered with red-baked shales overlying the coal seams attest to this propensity for these coals to burn for long periods of time following ignition. Typically, ignition in Fort Union coal is ascribed to spontanteous combustion. Range fires and direct lightning strikes have also been considered as possible sources of heat in some areas. Episodes of coal burning have created small clinker basins; these features and their cause have been described recently (Coates 1980, Heffern 1980). Heffern (1980) reports that on the Northern Cheyenne Reservation most thick beds have burned and that over 30 percent of the surface on the Reservation is covered by clinker. One coal bed, the Anderson, is reported to have burned over an area of 73 square miles (Heffern 1980). In North Dakota, a lignite seam has been measured as burning at a rate of 3 meters per year for a period of 100 years (Herring 1980). Probably the spontaneous burning of these beds began as soon as they became exposed by erosion along the present river courses, putting burning episodes into the Late Tertiary Pliocene-Pleistocene Epochs.

Other than the phenomenon of burning where exposed, postdepositional alteration of the coal-bearing strata has been rather limited. Erosion of strata has occurred along the major river courses where rocks have been removed down to the coal-bearing rocks (Fig. 1). No major mountain building events have occurred in the Powder River or Williston Basins. To the west, there has been deformation of Fort Union strata in the Red Lodge area and around the margins of the Crazy Mountain and Bull Mountain Basins (Matson and Pinchock 1977). Because of this lack of postdepositional activity, the major coal seams are nearly flat-lying except in areas where local small faults occur. There has also been no igneous activity associated with the coal beds, and coking coal and anthracite, which are formed under such regimes by metamorphism, do not occur within the Fort Union Formation coals.

SUMMARY

Paleocene-age rocks, bearing coal and lignite, are located in two major depositional basins in eastern Montana. The generally north-south-trending Powder River Basin, which begins east of Casper, Wyoming, enters the southern Montana area southeast of Billings and extends north to the Cedar Creek Arch. North and east of the Powder River Basin lies the Williston Basin, which extends east into North Dakota. These two basins were established as sites of deposition following the retreat of the Late Cretaceous seas. Across a broad, flat plain, large rivers deposited sediments from western, southern, and southeastern sources into the basins. Peats developed in backswamps and along coastal plains. These deposits were buried by subsequent flood or subsidence events and eventually developed into the present-day coal beds. At the close of the Paleocene, deposition of a more continental nature occurred, and coal deposition became relatively rare in Montana. Following burial and transformation of the peat to coal, erosion with gradual uplift exposed the coal in deeper river valleys and along the basin margins. These coal beds were thus exposed to spontaneous ignition, and this process has continued resulting in the large areas of clinker formed by coal fires. Today, the remaining coal resources of this area comprise one of the world's greatest sources of low sulfur coal.

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HISTORY OF THE COAL-BEARING ROCKS OF THE MESAVERDE GROUP IN NORTHWESTERN COLORADO

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HISTORY OF THE COAL-BEARING ROCKS OF THE MESAVERDE GROUP

IN NORTHWESTERN COLORADO

INTRODUCTION

Rocks of the Upper Cretaceous Mesaverde Group associated with coal mining in northwestern Colorado occur in Moffat and Routt Counties in the far northwest and extend south and east into Gunnison, Pitkin, Delta, Mesa, Garfield, and Rio Blanco Counties. In this area of Colorado two major geologic basins occur: the Sand Wash Basin in the north extending from Colorado into southern Wyoming, and the Piceance Creek Basin, which is the eastern part of the greater Uinta Basin of eastern Utah and western Colorado. These basins were once part of a single, original, depositional basin. They are now separated by the Axial Basin uplift, from which the Upper Cretaceous sediments have been subsequently removed. The remaining southern portion of this depositional basin in the Piceance Basin in Moffat, Rio Blanco, Garfield, Mesa, Delta, Pitkin, and Gunnison Counties. This basin is bounded by the Grand Hogback, a monocline in the east, the Axial Basin uplift on the north, Grand Valley and the Colorado River on the southwest, and the Gunnison uplift and the North Fork Valley on the south-southeast. The western boundary is set arbitrarily at the Colorado-Utah border. At the base, the known Mesaverde Group rocks cover an area of probably 7,500 square miles in the Piceance Basin. The Piceance Basin is deepest in Rio Blanco County, where sediments in excess of 25,000 feet have accumulated. It is one of the deepest basins in the Rocky Mountains. Eight coal fields are now producing or have produced coal from Mesaverde Group rocks in the Piceance Basin. These fields, located along the periphery of the basin, include the Lower White River field and the Danforth Hills field in the north, the Grand Hogback field and the Carbondale field along the eastern margin, and the Crested Butte, Somerset, Grand Mesa, and Book Cliffs coal fields along the southeastern margin to the Utah border.

To the north, in Moffatt and Routt Counties, the Sand Wash Basin, a southern extension of the Green River depositional basin, covers an area from the Wyoming line to the Axial Basin uplift and the Williams Fork Mountains on the south. This basin is bounded entirely by rocks of the Mesaverde Group. On the east, coal-bearing Mesaverde rocks occur along the Yampa River and Oak Creek (Fig. 1).

These two large basins contain huge reserves of both strippable and deep coal. It has been estimated that 1 billion tons of strippable coal occur in the Colorado portion of the Sand Wash Basin (Speltz 1976). In the Piceance Basin, a total reserve--including coal to a depth of 6,000 feet--of 56 billion tons has been estimated (Hornbaker and Holt 1978).

Rocks of the Mesaverde Group were deposited along the margin and interior of the Late Cretaceous depositional basin as a sequence of near-shore sediments of both marine and nonmarine origin. Lagoon, swamp, and beach deposits occur in the various named formations and members of the group, but the bulk of the

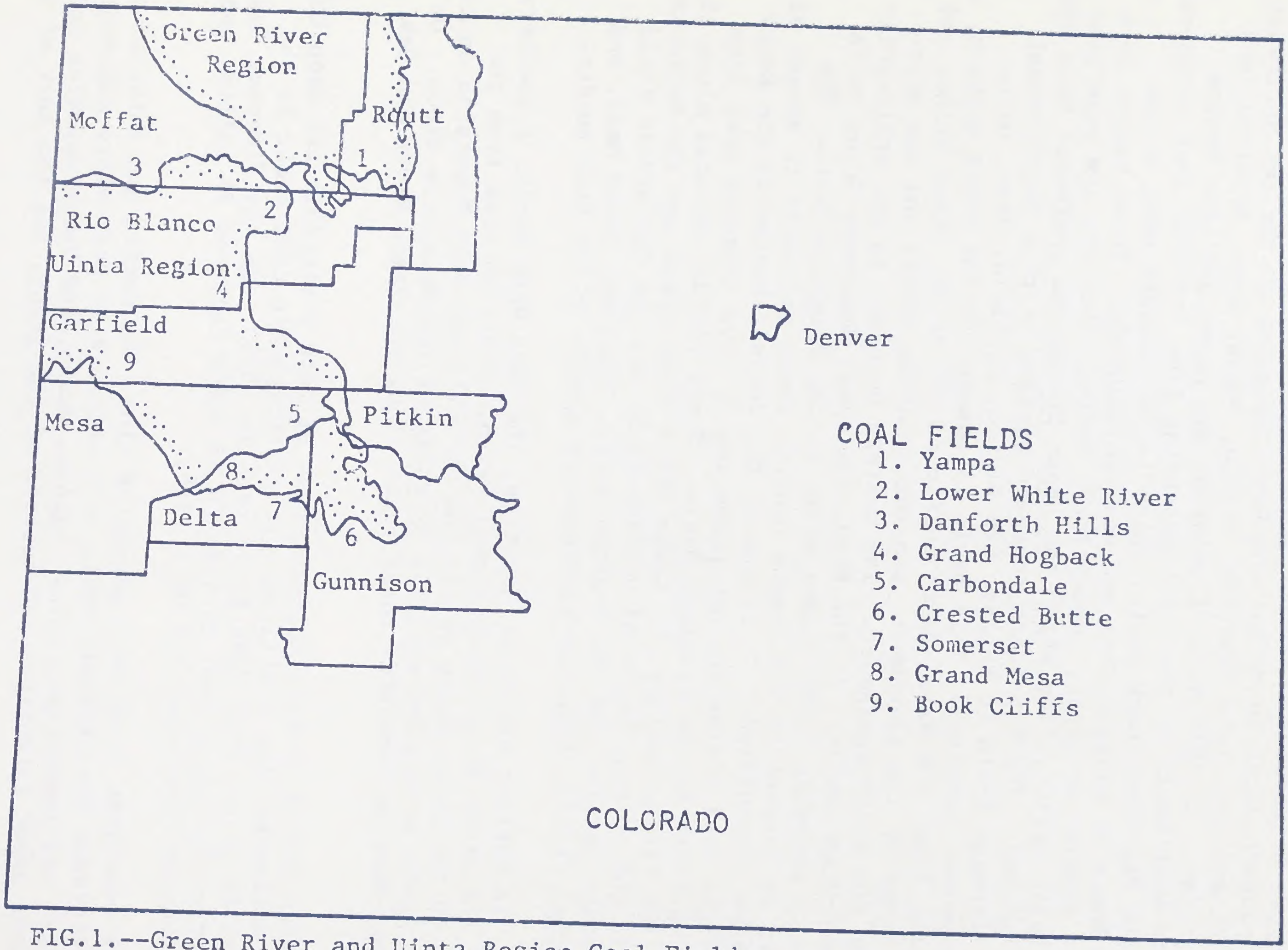

FIG.1.--Green River and Uinta Region Coal Fields.

sediments are of nonmarine nature. Deltaic deposition sequence and coastal plain sequences have been proposed as environments of deposition for Mesaverde rocks (Weimer 1960, Masters 1967, Collins 1976). Specialized studies of certain localities have led to varying interpretations of the depositional sequences found in these areas. In general, it is agreed that the sediments which now make up the Mesaverde Group were deposited near the margin of the Late Cretaceous epicontinental sea and that the alternating sequences of rock types were due to changes in sea level and more localized changes due to filling of swamps, change in rate of deposition, and general movement of shorelines during this period. Detailed analyses of some significant sequences will be attempted as they relate to the more detailed stratigraphy of the formations and significant layers found within the two basins.

ORIGINS OF DEPOSITION IN THE MESAVERDE GROUP

Rocks of the Mesaverde Group in western Colorado were deposited during the Late Cretaceous in and around the margin of a large epicontinental sea. To the east, Upper Cretaceous rocks are chiefly of marine origin, whereas the western area rocks are primarily nonmarine. The major feature of Upper Cretaceous deposition in Colorado was the gradual, eventual regression of the sea margin from west to east across the present Rocky Mountain area. No single-step retreat of the beach or strand line occurred during this period; instead, a series of alternating regression-transgression events took place, with the overall theme being retreat of the sea to the east. This gave rise to the cyclic deposition of sediments now seen as alternating facies in the Piceance and Sand Wash Basins. In determining the ancient environment for so large an area, undue emphasis on minor detail due to local variations in the environment of deposition must be avoided. After a broadscale interpretation has been made, more detailed analysis can fit local sections into the scheme with correction where necessary.

Some earlier workers considered the regional depositional model for the entire Mesaverde Group to be the rather simple one of coastal plain-sea margin attenuation described above (Young 1966). This model held that the marine shales below the lowest Mesaverde deposits, the Mancos Shale, were the expression of the offshore muds. Changes to a continental form of deposition through transitions from marine shale to sandstone and then to lagoonal or freshwater shales and coal seams were thought to be the result of fluctuations in sea level relative to the point of deposition through time. Figures 2 and 3 provide a schematic view of the regional geography and modes of deposition which occur when this model is accepted. In considering Figure 2 through a time sequence, the margin of the sea on the east would fluctuate along a generally east-west axis, and at a different time the sea margin would have been at a different point relative to the modern position markers--i.e., towns and political boundaries. However, the basic components of this model would remain constant. From west to east the paleogeography is assumed to have been as follows:

A highland area existed to the west from which detrital material was being removed and transported to the east. These highlands, which were areas of erosion and the major source of transported material that has been deposited

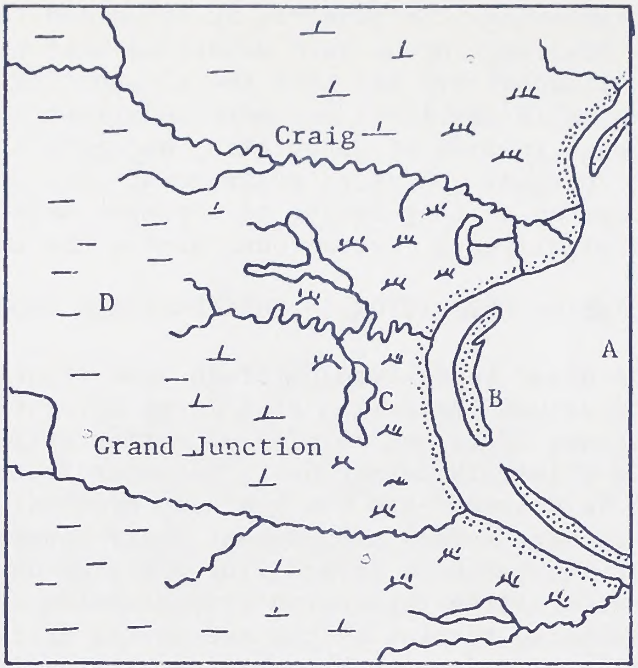

FIG.2.--Cretaceous Paleogeography. Coastal Plain Model. (After Curtis, 1962).

A. Ocean Basin
B. Barrier Islands
C. Coastal Plains, Swamps and Lakes
D. Upland

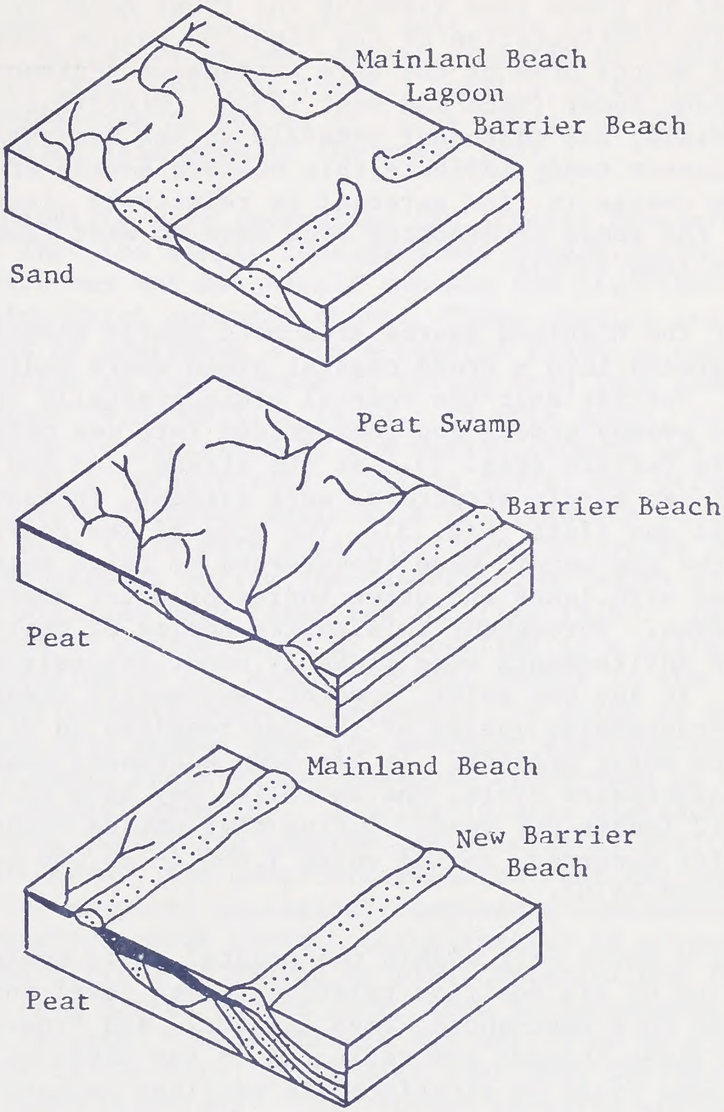

FIG.3.--Coastal Plain Environments. (After Young, 1966). The sequence of advance and retreat of the strand line through time-showing burial of the peat by marine and continental sediments.

in the Mesaverde rocks, were probably located in what is now central and western Utah. Just to the east of the highlands were alluvial deposits perhaps similar to those seen flanking the Front Range in Colorado today. The height and exact configuration of the highland source area cannot be measured today. In the source area of the late Cretaceous sediments, no deposits of the age are found today (Haun and Kent 1965). Distribution of materials, sizes of materials, and component minerals in the Mesaverde Group rocks exposed in Colorado today indicate this western source area, since the gradation from coarse to fine material is relatively clear, as is the relative thickening of the wedge of deposits from east to west (Haun and Kent 1965, Young 1966, Collins 1976).

To the east of the highland source area more gentle slopes were evident. These slopes graded into a broad coastal plain where sediments were deposited and reworked. Further east the coastal plain gradually changed to low, poorly drained, often swampy ground and then graded into sea margin lagoons, swamps, and river delta terrain (Fig. 2). At the strand line and in the near offshore areas, typical sea margin structures were evident, including beaches, offshore bars, and tidal mud flats (Fig. 3). The area of the coastal plain and lower areas nearer the sea margin were transversed by large meandering rivers and probably dotted with lakes and other bodies of water associated with lowlands and large streams. Throughout this entire period of geologic time, the representative environments were probably never entirely missing from this large region. At any one point, however, successive changes due to the transgression-regression cycles of the sea resulted in different expressions of the sequence being present. It has been estimated that during one Mesaverde transgression cycle, the shoreline may have advanced westward at a rate of 6 to 12 inches per year. During that entire transgression, 200 miles of lateral shift occurred, during which 1,000 to 65,000 feet of sediment were deposited (Weimer 1970).

An observer at a point well within the coastal plain would have seen the gradual lowering of his position relative to sea level and a gradual change from a dry land to a near-shore, then lagoonal, and finally a marine environment. These changes are reflected in the observed sequence of sedimentary rocks found in stratigraphic sections exposed in Colorado today.

In general, the present rock sequences were originally laid down under the conditions described in the transgression-regression cycles. The relations between these environments of deposition and the rock types seen today are divided into three main categories: marine, transitional, and nonmarine (Haun and Kent 1965).

These broad facies can be more finely subdivided, and this will be done when the detailed stratigraphy of the Mesaverde Group is described.

In the large scale, the presence of marine conditions at the time of deposition is represented by lime and marl stones, deeper water, and dark shales with interbedded limestones and sand or siltstones. The transitional marine to coastal environments are usually characterized by light-colored sandstones; characteristic deposits from barrier islands, beaches; and shallow, active water. Continental or nonmarine deposition ranges from coastal swamp shales and siltstones with discontinuous coal beds to dark barren shales. Farther inland, sediments become coarser, leading to sandstone and even conglomeratic layers (Haun and Kent 1965). Locally in the continental deposits there may be deposition of shales in large lakes, or the rather distinctive channel deposits laid down in the river beds.

Relatively recently, geologists have recognized and studied Mesaverde Group sections which indicate that the simple coastal plain transgression-regression cycles model of deposition may not adequately explain the distribution of the environments of deposition which occurred there. These studies indicate that in addition to deposition of sediments along a coastal plain, a considerable body of the rocks can better be interpreted as having been laid down in a deltaic environment (Weimer 1970, Collins 1976). In this model, much of the complexity of the Mesaverde is explained by the varied dynamic environments which occur in the delta of a large river. Collins (1976) has presented an interpretation of the eastern Piceance Basin as a southeast to south-advancing delta complex. In that area there were apparently several cycles of delta movement and sea level adjustment during the deposition of rocks of the Mancos, Iles, and lower Williams Fork Formation (Collins 1976). As shown in Figure 4, the distribution of environments of deposition in a delta is complex, and over the lifetime of the delta constant change in the spatial distribution of these environments occurs frequently. A delta is dynamic, since its growth rate and form depend upon its sediment distribution source, which may fluctuate on a small scale--i.e., seasonal flows--and on a large scale due to changes in channel geometry. A delta is also distinctly influenced by its receiving basin; its margins are altered by cyclic short-term tidal and storm influences, and long-term ocean current and sea level changes. Within the delta complex, biological components continuously alter the deposition sequences which occur there. Stabilization of slopes and levees by plant cover and filling of swamps by plant material may lead to a succession through time from barren mud to peat, then to herbaceous material, and eventually to large forests. These changes may well then be altered by physical events to result in the thin, lenticular coal beds derived from these compressed and altered plant materials. The closest existing analog of the eastern Piceance Basin delta may be the delta of the Niger River in West Africa (Collins 1976). Although an exact match between these deltas cannot be proposed, the physical features of the Niger delta will be outlined and compared with the known ancient features of the Piceance delta.

The Niger River rises in West Africa, Sierra Leone, and drains much of West Africa south of the Sahara (Allen 1970). After curving north and then east, the river turns south into Nigeria and enters its delta on the Gulf of Guinea through a narrow, 20-km-wide flood plain. As it nears the coast, the flood plain abruptly widens into a triangular area roughly 100 km wide perpendicular to the ocean margin by 350 km long at the coast. When the river enters this low-lying area, it branches into a network of smaller distributary streams, of which at least 19 have been named (Allen 1970). Each of these streams, where it enters the Gulf of Guinea, has formed an arc-shaped river mouth bar. Due

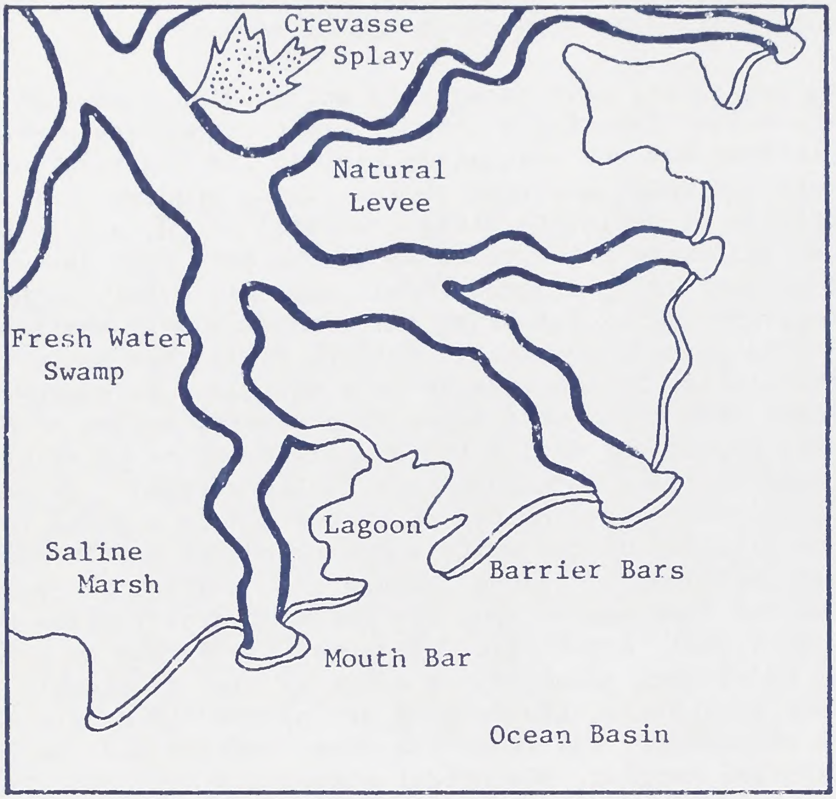

FIG.4.--Piceance Basin.
Generalized Delta Environments.
(From Collins, 1976).

to the moderate mean river sediment load of 2 X 10^7 cubic meters per year and the very energetic tidal and wave action, the Niger delta margin is largely balanced between these two forces (which tend to shape all deltas) and has relatively smooth curves on its seaward side when compared with the possibly more familiar bird's foot delta exemplified by that of the Mississippi River in Louisiana. The differences in the structure of these two deltas clearly illustrate the difference in form that result from the balances between sediment load and the energy regime of the receiving basin (Matthews 1974).

Within the Niger delta five depositionary environments from inland to sea margin are defined: the upper flood plain, where the river first slows and begins to branch; the lower flood plain, where branching and widening of the lateral area of the delta is pronounced; an area of swamps largely covered by dense stands of mangroves; a narrow beach barrier; and the subaerial mouth bars (Allen 1970). Deposits on the receiving basin slope rapidly from the delta front, through the prodelta slope and onto the open undersea shelf. In areas beyond the beach line, sediments are continually reworked and redeposited by wave and current action. Within all of these environments, sediments are continuously deposited in a complex sequence. The upper flood plain is dominated by the river and a few small tributaries. Between these are chiefly swamps and forests frequently flooded by overflow from the river. Sediments here are mainly sands, due to the high sand content of the sediment bedload of the river (Allen 1970). On the lower flood plain the small distributaries have built levees, and the areas between adjacent channels are filled with sandy alluvium and covered by a dense stand of vegetation. A mixture of plant debris and finer sediment produces extensive areas of dark silts and clays with interbedded layers of plant material (Allen 1970). Swamps dominated by mangroves extend laterally for more than 400 km along the coast of Nigeria. This environment is the expression of the interaction of tide and river-borne sediment. Tidal flow alternates across these swamps twice daily; so, sediments are continually in motion, and the area is interlaced with creeks and channels, through which fresh water flows to the sea and brackish tides pass alternately inland. Deposition is chiefly in the form of a complex of sands deposited in creek bars, organic muds in quieter areas, and layers of reworked plant debris, including large accumulations of driftwood (Allen 1970). With this model of the modern Niger delta in mind, the geometry of the rocks comprising the eastern Piceance Basin delta shows significant correlation with what one might expect from a similar depositional regime in the Late Cretaceous.

An interpretation of the Mesaverde Group rocks of the Piceance Basin as deltaic in origin depends upon recognition of structures and rock types which can be correlated with those found in recent deltaic sediment sequences. Collins (1976) has listed a number of these possible identifying characteristics important to this determination. But before beginning the comparison, it would be instructive to digress into the actual physical characteristics of the rocks of the Mesaverde group of western Colorado and establish their geographical and chronological relations as precisely as possible.

Terminology in this discussion will be informal, in keeping with the goal of the chapter, hopefully without offending the stratigraphic sensibilities of the professional geologist. The most important concept to establish is the distinction between rock units as three-dimensional bodies which are defined on the basis of their lithologic characters and rock-units as time-bounded sequences of deposition. Terms like "group" and "formation"--e.g., the Mesaverde Group and Iles Formation--refer to precise rock units defined by comparison to a type locality but which are not necessarily contained between well-delineated, isochronous boundaries. Time-related terminology--e.g., Late Cretaceous or Campanian--refers to worldwide, event-bounded sequences during which rocks were deposited. From the earlier discussion, it can be seen that at a single instant on a nearly level surface several sedimentary processes can be occurring side-by-side, and that following that surface today one would encounter a variation of rock types assigned on a physical basis to several formations. For example, a surface along a line perpendicular to the Late Cretaceous sea margin examined from a position some hundreds of meters off the coast might contain fresh muds deposited in shallow water, beach or bar sands, lagoonal muds, and peat or swamp land or freshwater alluvium farther inland. Today the sequence might well be assigned to several formally defined formations--for example, the Mancos Shale for the marine muds; the Tow Creek Sandstone, a member and lower marker bed, for the Iles Formation, and possibly the No. 1 Coal Bed of the Lower Coal Group of the Iles Formation. Other similar examples can be given across the proposed deltaic sequences described earlier.

STRATIGRAPHY

In the Sand Wash Basin, the Mesaverde Group rocks lie conformably upon the dark marine shales known as the Mancos Shale or Mancos Formation. These shales are interpreted as the offbeach silts and muds deposited prior to the beginning of the coastal or deltaic advance--progradation into the basin (Masters 1967). As such, they are not considered part of the Mesaverde Group. However, they do represent an environment of deposition which occurs periodically within the Mesaverde Group, where they represent the fluctuation of the delta front or strand line. In the Piceance Basin the Mancos Shale also occurs below the lowest Mesaverde Group sediment (Collins 1976). The Mancos Shale has been measured to be at least 4,600 feet in thickness in the Moffat-Routt County area (Fig. 5); (Bass _et al_. 1955).

The Mesaverde Group rocks are primarily nonmarine sandstones, shale, sandy shales, and coal beds (Fig. 5). The formations which make up the Mesaverde are the lower Iles Formation and the higher Williams Fork Formation. In the Piceance Basin the Mesaverde ranges from about 4,600 feet to 6,400 feet, with the greatest thickness reported in the northern area at the White River gap (Collins 1976). Collins (1970, 1976) has reported thicknesses for the Iles Formation from about 900 feet to 1,600 feet within the Piceance Basin, whereas in northern Routt and Moffatt Counties the formation is reported to be about 1,500 feet thick (Bass _et al_. 1955).

In detail, the Iles Formation (Fig. 5) is characterized by the sandstone units in its lower portion. These sandstone units go by different names, depending

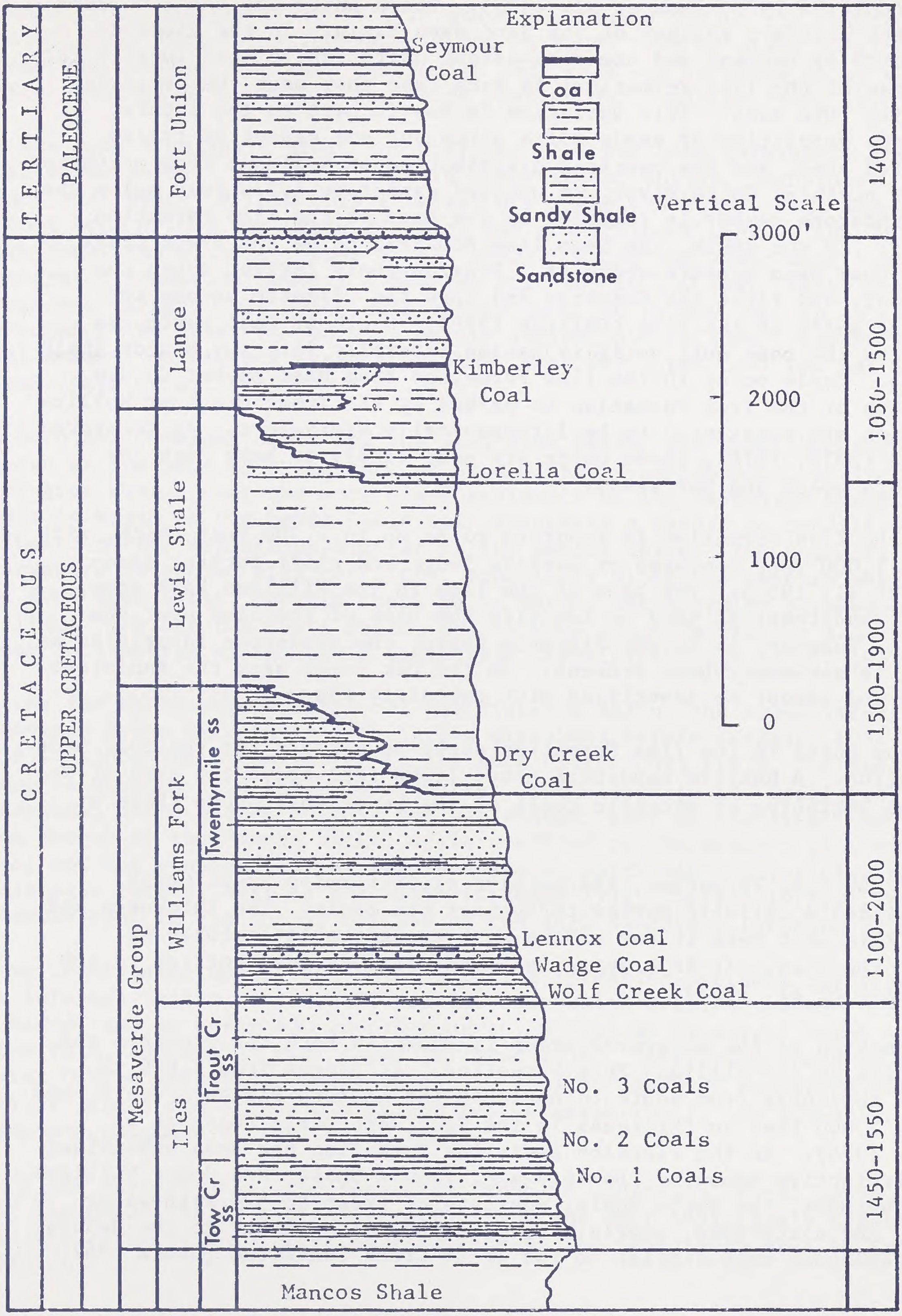

FIG.5--Generalized Stratigraphic Column.
Sandwash Basin. (After Bass, et al.,1955).

upon the location where they are encountered. Generally, the base of the Iles Formation is placed at the base of the first significant sandstone unit in the Mancos Shale (Collins 1976, Bass et al. 1955). These units are the Tow Creek sandstone in the northern reaches of the Sand Wash Basin. In the Piceance Basin, a sequence of unnamed and named sandstone units can be used locally for placing the base of the Iles Formation; in each case they meet the criteria for establishing this base. This variation is due in part to the lateral variation in the deposition of sands which pinch out and cannot be traced beyond a limited area, and the vertical distribution of sediment from north to south. In the north at White River, an unnamed sandstone 1,270 feet below the Trout Creek Sandstone member is regarded as the base of the Iles Formation (Collins 1976). To the south, the Sego lies 800 feet below the Trout Creek, and the first coal seam appears above it. Progressively farther south the Sego pinches out, and first the Corcoran and then the Cozzette become the basal sandstone units of the Iles (Collins 1976). South of Coal Basin the Cozzette remains the base unit until it passes laterally into the Mancos Shale (Collins 1976). Coals occur in the Iles Formation from near Meeker to New Castle. The top of the Iles Formation is marked by the Trout Creek or Rollins Sandstone, which are considered to be lithogenically equivalent. As interpreted by Collins (1970, 1976), these units are most likely to have been the prograding delta beach and bar sands.

In the north the Iles Formation is reported to be up to 1,500 feet thick, with the lowermost 1,000 feet composed of massive ledge and cliff-forming sandstones (Bass et al. 1955). The base of the Iles in the Williams Fork area, the Tow Creek Sandstone, is used to identify the base of the Iles over the Mancos Shales. However, as in the Piceance Basin, the sandstone identified as the Tow Creek is not everywhere present. In the Oak Creek area the sandstone becomes shaly and cannot be identified with certainty (Bass et al. 1955).

Other sandstone units in the Iles Formation serve as markers for the coal beds of this formation. A massive sandstone about 1,000 feet above the base of the Iles marks the beginning of mineable coals of the Lower Coal Group (Bass et al. 1955).

At the top of the Iles Formation, the massive cliff-forming Trout Creek Sandstone provides a reliable marker throughout the basin. The thickness and character of this unit make it one of the most recognizable features of deposition in the area. It is a white, massive, fine-grained unit up to 100 feet thick (Bass et al. 1955).

The upper formation of the Mesaverde Group is known in both the Piceance and Sand Wash Basins as the Williams Fork Formation. It ranges from 3,600 to 4,700 feet in thickness from south to north in the eastern Piceance Basin, and from 1,100 to 2,000 feet in thickness in the Sand Wash Basin (Bass et al. 1955, Collins 1976). In the Piceance Basin the Formation has been subdivided into three distinctive members: Bowie Shale, Paonia Shale, and Upper Williams Fork. The lowermost, the Bowie Shale, consists of fresh-to-brackish-water shales, coal, and siltstones, overlain by a marine unit similar to the Mancos Shale and a sandstone unit similar to the Trout Creek Sandstone (Hanks 1962;

Collins 1970, 1976). Above the Bowie Shale in the Coal Basin area, a second sequence of nonmarine rocks and coal beds occur above the second major sandstone interval of the Bowie. This member has been named the Paonia Shale (Hanks 1962; Collins 1970, 1976). Above the Paonia Shale, the remainder of the Williams Fork Formation--some 2,000 to 4,000 feet of mixed conglomerate, sandstone, shales, and thin lenticular coal beds--is referred to as the undifferentiated or upper Williams Fork (Hanks 1962; Collins 1970, 1976).

In the Sand Wash Basin area, the Williams Fork has been informally divided into three units. The lower unit is comprised of shales, sandstones, and major coal beds. Within this interval are found the Wolf Creek, Wadge, and Lennox beds of the Oak Creek district and some thinner beds in the Williams Fork Mountains district (Bass et al. 1955). Above the lower unit, the Twentymile Sandstone Member, a massive unit 100 to 200 feet thick, forms a prominent marker. The upper unit varies from 200 to 850 feet in thickness throughout the area; it contains mainly shales, and in some areas workable coal seams. In the Dry Creek area, the thick Dry Creek Coal bed has been mined (Bass et al. 1955).

In both the Piceance Basin and the Sand Wash Basin, the upper boundary is placed at the base of a sequence of predominantly homogeneous, marine, dark-grey shales over the more mixed sediments of the Mesaverde Group. This shale is known as the Lewis Shale and represents a return to condition of offbeach marine deposition similar to the Mancos Shale. The boundary cannot everywhere be placed with certainty, especially along the western margins of the Sand Wash Basin, because there is no marked unconformity between the upper Williams Fork and the Lewis Shale, and in some areas lenticular sandstones occur in a matrix of the Lewis Shale-type deposition (Bass et al. 1955).

In the far southwestern margin of the Piceance Basin, the nomenclature of the Mesaverde Group differs from the areas discussed before (Erdmann 1934, Young 1959). Along the Grand Valley in the Book Cliffs Coal Field, the Mesaverde Group is divided into three lower units: the oldest is the Castlegate Sandstone, which occurs only in the westernmost part of the area; next is the Buck Tongue of the Mancos Shale, again confined to the western part of the area; and the youngest is the Sego Sandstone, which has similarities to sandstones farther east in the basin (Erdmann 1934, Collins 1976). There is mineable coal in the Anchor Coalbed of the Sego Sandstone (Erdmann 1934).

Above these basal units, the Mount Garfield Formation has been described in two informal units: a lower 300-to-600-foot-thick section called "coal measures" and an upper 400-to-670-foot-thick "barren measures" which has only a few thin, unmineable coal seams (Erdmann 1934). Overlying these is the Hunter Canyon Formation, composed of 370 to 1,000 feet of sandstone with a smaller percentage of shale near the top (Erdmann 1934). No mineable coal seams occur in the Hunter Canyon rocks.

As in the eastern area, the Mesaverde Group is underlain by the Mancos Shale. Over the Mesaverde is a conglomeratic sandstone unit tentatively identified with the Tertiary Ohio Creek Conglomerate of the Grand Mesa area by Erdmann (1934).

Coal beds or groups of coal beds ("zones") may have been named in each coal field in the Mesaverde Group Formation. These named beds or zones are generally only very locally applicable. Sometimes even adjacent districts of a single coal field may have differing names for what may appear to be the same coal seam. Returning to our earlier discussion of the environments of deposition and considering the length of time over which these formations were deposited, the variation in coal seams should come as no surprise. Rather than attempting a detailed analysis of the stratigraphy of each named bed or seam, only a discussion of the major coal zones and their position relative to the boundaries of the formation in which they occur will be made. The descriptions to follow are modelled closely on those which occur in the Keystone Coal Industry Manual for 1980.

Beginning in the far southwest and working around the margin of the Piceance Basin of the Uinta region, the named coal fields are encountered in the following order:

The Book Cliffs Field in Mesa and Garfield Counties has six named coal zones: beginning from the bottom, they are the Anchor Mine Coal Zone (which occurs in the Sego Sandstone), the Palisade Coal Zone, the Corcoran Coal Zone, the Cozette Coal Zone, the Cameo Coal Zone, and the Carbonera Coal Zone (all in the Mount Garfield Formation). The Corcoran, Cozzette, and Cameo zones are associated with named sandsone units at their base.

The Grand Mesa Field, mostly in Delta County but extending on the northwest into Mesa County, is similar to the Book Cliffs, with the primary coal zone occurring in the Mount Garfield Formation.

The Somerset Field is located in Delta and Gunnison Counties, where six coal zones have been named, all in the Williams Fork Formation. These zones are, beginning from the lowest, "A" through "F." They occur in about 500 feet of the Bowie and Paonia members of the Williams Fork Formation.

The Crested Butte Field in Gunnison County has been severely deformed since its deposition and the coal altered to a higher grade. No specific coal stratigraphy is given for this field.

The Carbondale Field in Garfield and Pitkin Counties also has undergone considerable past depositional alteration and now produces high-grade coking coal. In the Carbondale Field, coals occur in the Iles and Williams Fork Formations. The Corcoran and Cozzette Zones occur in the Upper Williams Fork Formation, and the Iles Formation may have four major zones. These are variously named as the "A, B, C, and D" zones at the base just above the Rollins or Trout Creek Sandstone, the Dakota Creek, Sunshine or Placita, and the Keystone. In all, these zones occur within 1,700 to 2,000 feet of strata.

The Grand Hogback Field extends along the Grand Hogback from Meeker in Rio Blanco County south through New Castle and Glenwood Springs into Garfield County. Along this structural monocline, the coals dip westward at 40° to near vertical. The zones are the same as those for the Carbondale Field, with the greatest production having come from the Keystone Zone, the Corcoran and Cozzette Zones (also known as the Black Diamond Coal "Group"), and the Fairfield Coal "Group," which contains zones "A through D" in the lowest Williams Fork Formation.

The Danforth Hills Field in Rio Blanco County and southern Moffat County borders the Axial Basin where the Upper Cretaceous rocks have been removed. In this field, coal zones occur in the Iles Formation as the Corcoran Coal Zone, the Meeker Coal Zone, the Sulfur Creek Coal Zone, the Wilson Coal Zone, and the Pollard Coal Zone. These five zones occur in about 1,100 feet of rock between the Sego Sandstone and the Trout Creek Sandstone. In the Williams Fork Formation in this field, 11 coal zones have been named. These are, from lowest to highest, the Major, Bloomfield, Fairfield No. 1, Fairfield No. 2, Wesson, Agency, James, Cornrike, Grinstead, Montgomery, and Lion Canyon Coal Zones. They occur in about 4,000 feet of strata.

The lower White River Coal Field in Rio Blanco and Moffat Counties has coal zones similar to those of the Danforth Hills Coal Field to the east.

In the Sand Wash Basin of the Green River Coal Region, there is only one named coal field, the Yampa. Coals occur and have been locally mined in the interior of the basin from Younger Tertiary (Fort Union, Paleocene) strata, but these were isolated, generally small family or wagon mines. Within the Yampa Coal Field the Iles Formation has six coal zones aggregated into the "Lower Coal Group." These are, from lowest, #1, and "A" through "E" coal zones. In the overlying Williams Fork Formation, the nomenclature continues with coal zones "F" through "S" for a total of 14 named zones in the Williams Fork. Within these zones, the "H" contains the Wolfcreek beds, the "I" contains the Wadge Coal Seam, and the "J" contains the Lennox Coal seam.

It can be seen from this listing of the fields and their named zones that correlation between fields is a topic which has always been of interest to the group most concerned with continuity of coal beds--i.e., the coal miners. From the geologist's point of view, there will probably never be a totally satisfactory correlation between fields or districts or mines for the simple reason that the coal beds are discontinuous in space and were laid down at different times.

The most important general idea proposed earlier in the discussion of environments of deposition can now be addressed and some conclusions about the Mesaverde Group and its origin attempted. If we accept the idea of a coastal plain environment with deltaic sedimentation superimposed upon the original totally marine environment of the Mancos Shale, then the reasons for the discontinuities of coal seams and the various other rock facies become apparent. The movements of beach lines and their related environments will produce cyclic sedimentation relative to the modern geography. Even though the Mesaverde Group rocks were deposited in a single continuous basin, local variations, determined by the coastal geography and the source and distribution of sediments, have occurred (Young 1955, Weimer, 1960). The relative positions of the strand line during the various regression-transgression cycles have been delimited in several publications; usually these are based on Weimer's (1960) work. An especially good presentation is made in the Rocky Mountain Association of Geologists of 1972 Geologic Atlas of the Rocky Mountain Region of the United States of America.

Variation in depositional environments in the deltaic model as proposed by Collins (1976) for the Piceance Basin has associated with it a different sequence of distribution sediments with an overall complexity probably greater than that of the coastal plain-lagoon deposition model. The characteristic features of the eastern Piceance Basin which make the deltaic model preferable to the coastal model are as follows (Collins 1970, 1976); (1) The paleocurrent features of the Trout Creek and Williams Fork Sandstone units trend perpendicular to the shoreline. (2) Beach or lagoonal deposits are not found beneath the Mesaverde coal seams, and variations of the coal seam "splits" are too variable for a regional transgression model. (3) Direct information on the environment derived from the fossil record indicates the presence of a freshwater swamp, i.e., broad leaved trees and conifers, rather than a marine or brackish swamp. There is also an almost total absence of the types of animal fossils typical of lagoons. (4) From a geologic perspective, there is the lack of continuity of beds, as demonstrated by their stratigraphic position, geometry, and character, which would be associated with a general regional subsidence. (5) The amount of freshwater channel sand and siltstones is greater than that expected in a coastal plain-lagoon deposition model.

The deltaic deposition model has received widespread acceptance in recent publications on the Late Cretaceous throughout the area where rocks of this time interval have been deposited in the western interior of North America (Collins 1970, 1976; Weimer 1970, Siemers 1978; Billingsley 1978). In final consideration, it will probably hold that the depositional sequences in the Mesaverde Group can best be interpreted as coastal with the sediment being brought from the west and with primary deposition occurring along a river delta-dominated shoreline.

POST-DEPOSITIONAL EVENTS

Following deposition of the Mesaverde Group, a series of major orogenies occurred in the region which eventually broke up the single Late Cretaceous basin of deposition into a series of uplands and interior depositional basins (Weimer 1960, 1977; Collins 1970, 1976). These tectonic events continued into the Tertiary, and major Tertiary coal deposits occurred in the intermontane basins. For example, in the Sand Wash Basin during the Late Cretaceous, coals were deposited in the Lewis and Lance Formations, and later in the Tertiary (Paleocene) in the Fort Union Formation (Seymour coal; Bass et al. 1955). To the east, the North and Middle Part Tertiary coals were deposited in another of these interior basins (Weimer 1977). The area now separating the Sand Wash and Piceance Basins, the Axial Basin uplift, is presumed to have received sediment during the Late Cretaceous, but these rocks were removed by erosion following uplift. Along the east margins of what are now the Sand Wash and Piceance Basins, the uplifts created the mountain ranges which so prominently separate the basins. Further to the east, the Front Range eventually emerged, and the present structure of Colorado became definitively outlined.

Along the Grand Hogback, the activity related to uplifting created the steeply dipping margins of the Hogback, the Elk Mountains, and to the north, the Danforth Hills (Collins 1970, 1976). Folding that led to the Grand Hogback, the White River uplift, and the West Elk Mountans has been dated by stratigraphic and radiometric methods to the Middle Eocene-Early Miocene times.

In addition to altering the formerly horizontal aspect of the sediments, these earth movements have altered the rank of coals where high compression and heating during igneous activity have occurred near coal seams. Significant igneous activity in the coal areas occurred, in particular, in the Aspen Gulch-Four Mile Creek area, near Coal Creek, and in the Coal Basin area (Collins 1976). The metamorphism of coal seams associated with dikes and sills of the igneous activity has produced locally altered coals ranging from the high-volatile bituminous B and C coals to the high-volatile A and even the anthracites characteristic of the Crested Butte Coal Field. The coking qualities of the coals have been altered by their association with intrusions and heating. In areas of intense local heating in the Coal Basin area, there are naturally "coked" segments which occur in the coal bed adjacent to the intrusives (Collins 1976).

SUMMARY

In summary, the rocks now known as the Mesaverde Group were deposited along the margin of the sea which dominated deposition in the western interior of the United States for most of the Late Cretaceous. The present area underlain by the Mesaverde Group rocks was a part of a large continuous basin which received sediments from a highland source area in what is now central and western Utah. The total period of deposition of sediments now known as the Mesaverde Group occurred in the Campanian and probably occupied a period from 80 to 70 million years before the present.

Two models for deposition of the coal beds are possible. One is a simpler coastal plain-lagoon model in which the lateral variations now seen are interpreted as resulting from changes during the transgression-regression cycles of the sea margin (Young 1955). The second, which seems to be gaining increasing acceptance, is that of a sea margin dominated by large river deltas with their accompanying variation in geometry and sediment distribution (Weimer 1970). Present discontinuities of the coal beds are explained by both models, but the extreme variation seems to favor the deltaic model (Collins 1976). In either case, large accumulations of peat from the plant communities which dominated the landward side of the basin accumulated under conditions favorable for their burial and preservation as today's coal.

The alternation of coal and inorganic sediment clearly demonstrates the dynamic events which created the varying environments. Plant materials associated with the coal seams were produced in extensive swamps dominated by broad-leaved hardwoods and conifers (Tidwell 1966). Large dinosaurs were present, as evidenced by tracks and fragmentary fossilized bones found in the strata. Following the final stages of Mesaverde sedimentation, earth movements associated with the major orogeny in the present central Rocky

Mountain region altered the paleogeography, and the overlying Cretaceous and Tertiary sediments were laid down in river-dominated intermontane basins. Subsequent Tertiary igneous activity has significantly altered the character of some of the coal in localized areas, producing the high-rank coking coals of Pitkin and Gunnison Counties. The geometry of the coal-bearing strata as seen today is therefore a function of the original basin of deposition and post-depositional earth crustal movement. The qualities of the coal are equally determined by the original plant materials which constituted the peats and their subsequent history, including heat and compression metamorphism.

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COAL DEVELOPMENT

AND

ASSOCIATED RESOURCES:

PHYSICAL

COMPARATIVE IMPACTS
OF
MINE-MOUTH AND OFFSITE COAL UTILIZATION

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INTRODUCTION

Purpose and Scope

The purpose of this analysis is to describe the comparative operational, environmental and economic impacts of mine-mouth versus offsite utilization of coal for electric power generation and coal gasification processes. The area of major interest involves the states of North Dakota, Wyoming, Montana and Colorado.

Such impacts derive from the siting of coal extraction, transportation, handling, storage, and utilization facilities in an area with unique resource characteristics and environmental constraints. Installing such facilities involves detailed planning and strategic analyses; requires specific manpower, materials, equipment, water and land inputs; and results in possibly adverse air emissions, water effluents, solid wastes, noise and occupational health and safety outputs. The net impact can be reflected in comparative capital and operating and environmental costs for the required facilities and in sociological costs borne by the community in sustaining the work force necessary to construct and operate such facilities.

The analytical format involves describing the general resource and environmental background of the study area and the nature and type of technologies to be imposed on the area; specifying the comparative operational, environmental and economic impacts of such technology; and presenting example impacts generated by various types and sizes of actual and hypothetical installations.

General Background

Impact analyses are meaningful only within the context of the unique geologic, geographic and climatic environments of the study area and as affected by the required inputs and outputs of the alternative processes and facilities involved. The following regional, technologic and process descriptions are provided, however, only to the extent necessary to provide understanding specific on-site impacts.

Resource Base

The coal reserves of the study area, as well as of the United States and the world, are sufficient to last several hundred years at currently proposed rates of consumption. The demonstrated reserve base of the United States constitutes approximately one-third of world reserves and exceeds 474 billion tons of in-place coal (Keystone Coal Buyers Manual 1979). The reserve base for the study area (shown by Table 1) constitutes 45 percent of these national reserves on a tonnage basis.

The in-place value of any coal, however, derives from its "rank" as determined by constituent ratios, from its geographic location relative to demonstrated energy needs, and from its "mineability" as determined by the geologic factors of occurrence. Bituminous coals are geographically widespread, have a heat

TABLE 1. DEMONSTRATED RESERVE BASE OF COAL IN THE UNITED STATES, JANUARY 1, 1979, BY RANK*

State	Anthracite	Bituminous	Subbituminous	Lignite	Total
Colorado	25.5	9,106.3	4,117.3	2,965.7	16,214.8
Montana	-	1,385.4	103,317.8	15,765.7	120,468.8
North Dakota	-	-	-	9,971.2	9,971.2
Wyoming	-	4,482.0	65,632.0	-	70,114.0
Subtotal	25.5	14,973.7	173,067.1	28,702.6	216,768.8
All Others (28 states)	7,319.9	226,901.2	9,375.9	14,190.3	257,787.3
Total	7,345.4	241,874.9	182,443.0	42,892.9	474,556.1

Source: *Keystone Coal Buyers Manual* 1981.
* Measured and indicated in-place reserves; figures in million short tons.

content of 11,500 to 13,500 British thermal units per pound (Btu/lb), and are used for metallurgical, power generation and industrial heating purposes. Subbituminous coals are found mainly in the western states and have a heating content of 8,000 to 10,000 Btu/lb and a high moisture content. Anthracite has a high heat content (13,000 Btu/lb) and a low sulfur content and is currently significantly found only in the northeastern United States.

Colorado coals are predominately bituminous coal with lesser amounts of subbituminous coal and lignite; these coals underlie nearly 30,000 square miles of the state and constitute 21 separate coal fields. Ninety-five percent of the reserves are accessible only by underground methods, although surface methods account for more than 50 percent of current production.

Montana has by far the largest amount of identified reserves in the United States, with rank covering the full range of occurrence. The state possesses more than one-half of the reserves of the total study area in 17 identifiable coal fields in the eastern two-thirds of the state. Current production is attributable to surface mine operations.

North Dakota lignites occur over a 28,000-sq-mi area, in six regions, with commercially significant reserves in the Great Plains region. Current production is entirely by surface methods and is used for power generation; limited future production is planned for gasification purposes.

The bituminous and subbituminous reserves of Wyoming underlie more than 40,000 sq mi and have been subdivided into 45 separate coal fields. Production is almost totally by surface methods for power generation purposes.

Physical Environment

The unique physical environment of the study area gives rise to several concerns regarding the impact of regional coal extraction and utilization. These include possible air quality deterioration, adverse effects on scarce water resources, revegetation of reclaimed areas in arid or semiarid regions, population impacts on existing community infrastructure and possible harm to wildlife populations and archaeological resources. Such concerns could restrict or even prohibit future mine development and absence of appropriate planning, design and reclamation measures. Approximately five percent (1 billion tons) of currently leased federal coal reserves in the western states could be adversely affected by such concerns. These concerns are compounded since the low unit value of the low-ranked regional coals precludes their transport over long distances and encourages utilization in on-site power plants or synfuels facilities.

The Surface Mining Control and Reclamation Act of 1977 (SMCRA) addressed most of the concerns about the environmental effects of western coal mining and also established performance standards for mining and reclamation that must be met before permits can be approved. The act is administered largely by the States, with Federal oversight responsibility. Various other statutes, as the Clean Water Act (as amended, 1977), the Clean Air Act (as amended, 1977), and legislation to protect wildlife, also affect coal mining operations. In addition, the Federal Land Management Policy Act of 1976 (FLPMA) included environmental provisions in the Federal coal leasing program.

Air quality is of major concern in areas where mine-mouth powerplants are located, especially along political boundaries such as State lines or national parks. A good example of the migration of fugitive dust and general airborne pollutants is North Dakota lignite.

Since such lignite is uneconomical to transport over any distance it must be sold to onsite or nearby power plants or synfuels facilities. Permitting of additional coal conversion facilities in west-central North Dakota could be delayed, pending further information on the effect of existing and permitted plants on the air quality of nearby Theodore Roosevelt National Park.

Additional Federal coal development could be affected by possible fugitive dust problems. At Colstrip, Montana, where fugitive dust levels presently exceed ambient air standards, future mine expansion will have to address and minimize air impacts.

Water resource concerns could affect the recovery of coal reserves that underlie alluvial valley floor significant to farming. Although such concerns could affect over 700 mmt, less than 100 mmt may be prohibited from mining. Spoil handling and protection of raptor habitat have removed 5 mmt of recoverable reserves from mining in southern Wyoming and could affect as much as another 50 mmt in southern Wyoming and northern Colorado. Development of 29 mmt has been delayed in west-central North Dakota because of concerns about reclamation of wooded draws.

Market Factors

Most energy forecasts predict that the major Federal coal states in the West will attract larger shares of the total coal market over the next 10 years. Several studies project that Western coal, which supplied 28 percent of the 1979 U.S. demand, will supply as much as 49 percent of the market by 1990. Many factors will influence this demand but three are significant: demand by domestic electric utilities, growth of non-utility markets, and transportation availability and cost.

The principal markets for Western coal are utilities in the Western coal-producing states, the Midwest, and the South-Central states. The electrical growth rates in these regions will be the most important factor affecting demand. Other factors shaping demand include growth rates and fuel preferences for new plants in regions not currently burning coal and the extent of conversion of existing oil or gas-fired power plants to coal. The present new source performance sulfur dioxide emission standards, which require sulfur reduction of all coals (thus reducing the cost advantage to utilities of burning low-sulfur coal), and the recent decline in electrical growth rates suggest that the growth in Western coal demand might not be as high as earlier forecasts had predicted.

Access to reliable, efficient, and low-cost transportation is critical to the success of Western coal producers in selling to out-of-state coal markets. In all Western coal regions, coal transportation costs are increasing. Because these costs can account for over 70 percent of the delivered price of coal in out-of-state markets, the competitive position of Western coal in these markets is not likely to be as favorable in the next 10 years as it was in the previous 10 years.

Socioeconomics

Recent large-scale coal mining has brought rapid growth to Western rural towns that have been hard pressed to deal with the sudden influx of people. They have found themselves short of housing, municipal services, health care facilities, and other elements of an extensive community infrastructure.

The ability to solve such problems is hampered by a lack of timely revenues since facilities and services are needed before new local taxes are available. Several means have been used to meet such costs including state severance taxes and private revenue contribution as prepayment of taxes.

However, considerable debate exists over whether existing private and governmental programs will be adequate to meet the financing and other needs arising from the management of energy development growth. Federal coal development in the 1980s, especially in areas where other kinds of rural industrialization (such as synfuels and powerplant development) are occurring, could strain the capacities of communities in the Powder River Basin, the western slope of Colorado, central and southern Utah, and the San Juan Basin of New Mexico.

OPERATIONAL PROCESSES AND IMPACTS

The intent of this section is to describe the comparative processes involved for onsite and offsite coal utilization for power generation and gasification purposes and to present comparative input-output impact summaries for selected facilities.

Extraction

Since the nature and type of extractive methods and techniques for coal recovery have been described in previous sections, they will not be repeated here. It is sufficient to note that overburden removal and coal recovery are predominantly by surface methods that utilize some combination of draglines, shovels, or front-end loaders. Coal loading is either from single or multiple seams after ripping or blasting operations. The nature and extent of overburden preparation required are functions of the type of material overlying the coal deposit.

OnSite Transport

Coal is moved from the point of extraction to either storage or load-out facilities for movement to onsite or distant utilization facilities.

Some combination of truck and conveyor transport is normally utilized for such movement. The selection of the number, type and capacity of trucks to transport coal from the extraction point to such facilities involves considering the length and geometry of the haul distance, the cycle time and capacity of loading equipment, and the haulroad design criteria and intended life. Truck sizes vary from 35 to more than 150 tons capacity. Haulage speeds may exceed 50 mph.

Haul-road design is important since it affects vehicle fuel consumption, speed, life, operator efficiency, repair costs, downtime, and operator health and safety. Haul roads may be located in the pit, between the pit and the coal storage and load-out facilities, or between the pit and the coal utilization facility dumping point. Road widths vary up to three and a half times the width of the haulage unit. Water and other wetting agents are used to: control fugitive dust, maintain road surfaces, and assist operator visibility.

Belt conveyors may be used to move material from the point of truck unloading or from storage to the utilization point. Conveyor transport produces a steady flow of material for processing; requires lower investment costs than road transportation; easily crosses roads, railways and difficult terrain; and enables uniform electric consumption and low maintenance costs (Pelzer 1979). Transport is subject, however, to constraints of haulage distance, size of material handled and material moisture characteristics.

Belt speed and width are dependent on specific design considerations but one typical installation in North Dakota utilizes a 72-in. belt traveling a one-mi distance to the truck dump and the plant.

Material Storage and Handling

The substantial costs and time required to develop and operate coal storage areas for operational convenience and flexibility are often underestimated. Considerable land areas may be required to accommodate the facilities involved.

Major design criteria include material properties, climatic and site conditions, flow rates, reclaim methods, blending requirements, stockpile shape and type of receiving and delivery equipment (Colijn and Vitunac 1979). The objectives are to optimize land usage, maintain material properties, minimize capital and operating costs, and maintain access ease.

Storage may utilize open-ground methods involving combinations of ramp, conical, radial, rectangular or block piles, emplaced by trucks, dozers, elevated belt trippers, stacking bridges, stacker booms or bucket wheel stacker/conveyors. Pile dimensions may vary from 25- to 100-ft heights, with volumes in excess of 40,000 tons. Capital costs vary from \$30 to \$50/m^3 of capacity. Areas required for open storage, in square feet per ton of 100-lb material, vary from 0.25 to 3.1 depending on pile configuration and stacking equipment.

Ground storage may utilize conical-shaped, tent-shaped or box-shaped domes, arches or buildings to protect porous, soluble, dusty or easily contaminated materials; it may also use elevating tripper conveyors for placement and reclaim tunnels for recovery. Capital costs for storage are shown in Figure 1.

Silo storage, common in units of 60,000 to 160,000 tons, may be used to maximize covered storage volumes on limited or restricted land areas.

Reclaiming coal from storage may utilize front-end loaders, scrapers, tunnels, overhead bridges, bucket wheel reclaimers or some equipment combination, depending on the desired loading rate and the rate and the ratio of dead to live storage. Reclaim rates vary from one to 7,000 t/hr, for gravity tunnel feed and for bucket wheels, respectively.

Coal Preparation

Coal properties may be significantly altered by cleaning, blending and crushing, which affect the ability of a coal to meet use specifications. Coal characteristics, such as moisture, volatile matter, sulfur, ash, agglomeration, heat content, fusion temperature, etc., control the use of a given coal as a steam, coke, industrial, or synthetic fuel product. More importantly, the emissions these coals produce during combustion affect production and use. The cost of compliance with the Clean Air Act is a dominant control on producing coal.

Western coals, however, are generally lower in sulfur than eastern coals and such extensive preparation as noted above is unnecessary. Comparison on an energy-equivalent basis, however, yields almost identical sulfur content per Btu. The transportation costs of reaching consumption areas in the midwest and east narrow the benefit/cost comparison even more. The inherently high moisture content of the low rank coals is detrimental as it increases the cost of transportation on a heating value basis, reduces boiler efficiency, causes derating when burned in boilers not specifically designed for such coal, causes freezing of coal in railroad cars, and is subject to spontaneous combustion in stock piles and railcars. Normal beneficiation practices may involve size reduction of as-received lignite for subsequent use in pulverized fuel-fired electric generating plants, for use in cyclone-fired boilers, or for use in spreader stokers. Boiler design considerations include high moisture, pulverization characteristics, and often high ash content.

Utilization

Utilizing coal reserves in the study area may involve converting to liquid or gaseous fuels or direct combustion for electric power generation. The intent of this section is identifying the existing and proposed technologies involved and describing relevant environmental, health, and safety impacts.

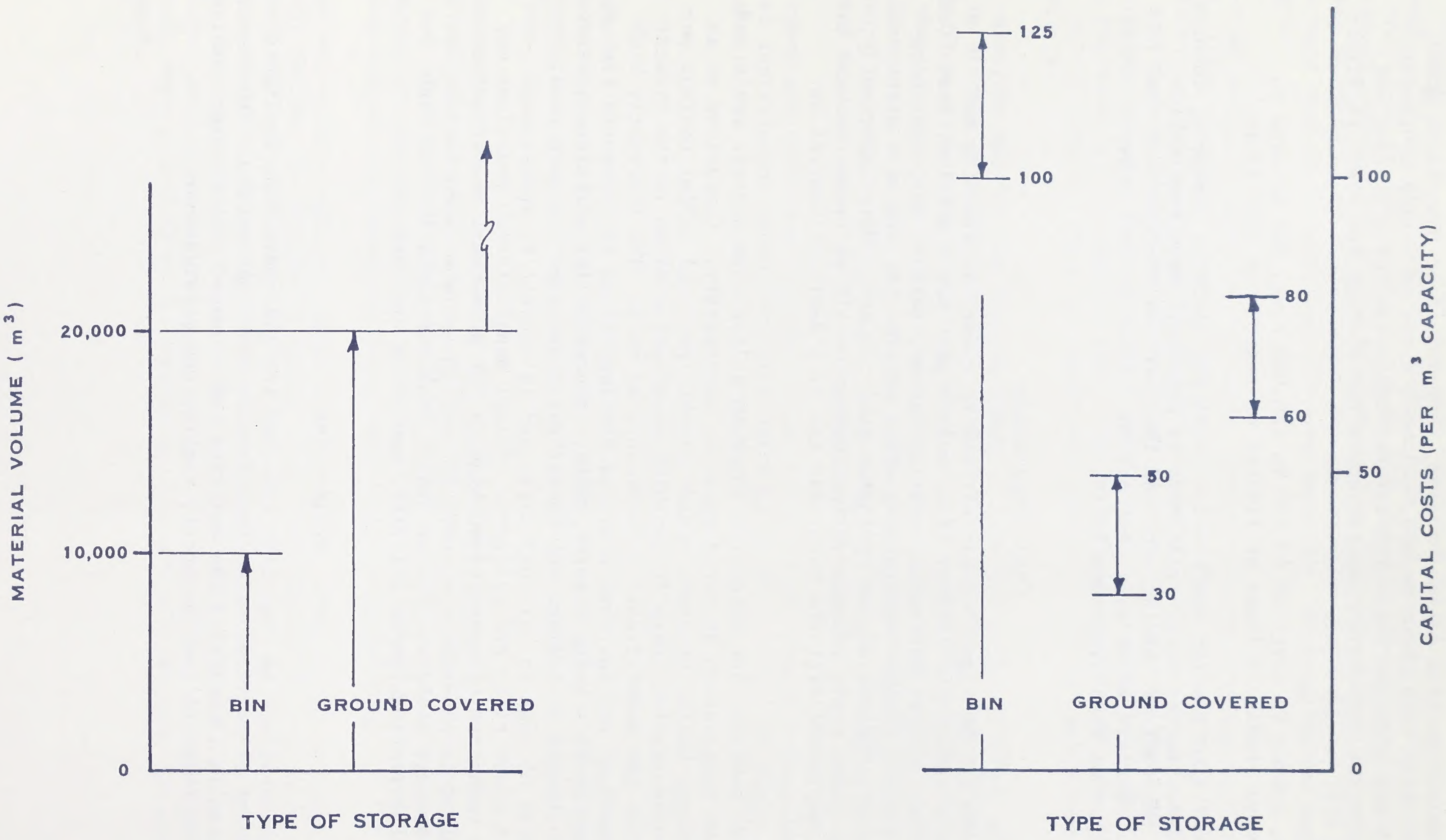


Figure 1. Capital costs and capacities for various storage types. Source: Colign and Vitunac 1979.

Liquefaction and Gasification

The purpose of liquefaction is producing cleaner burning liquid or gaseous fuels that are easier to transport, store and use (DOE 1977). "Direct" liquefaction involves coal slurrying with a solvent and subsequent hydrogenation under conditions of high temperature and pressure (Rice 1981). The process is of production significance historically in Germany, but no plants exist in the United States for commercial production. Development work is proceeding on six processes (Solvent Refined Coal Processes I and II; EXXON Donor Process; H-Coal Process; Modified I.G. Farben Process; and ICRC Demonstration Process). The complex nature of the chemical processes involved, the magnitude of estimated product costs involved ($35 to $55/b), the high investments required ($30,000 to $55,000/bsd), and the lower quality of the coal liquids now producible probably preclude commercialization until the mid 1990s.

Indirect liquefaction denotes initial conversion of coal to synthesis gas (CO and H^2) and subsequent conversion of this gas to various types of liquid fuels. Synthesis gas is commercially feasible, with South Africa expected to produce 120,000 bd during 1982. Conversion of synthesis gas to methanol (gasoline-blending component) is probably the most likely future development in the United States, although the conversion of methanol to a premium grade gasoline is possible.

Three methods currently exist for the commercial gasification of coal (Lurgi dry-bottom, Kippers-Torzek, and Winkler) and three are under development (Texaco, British Gas/Lurgi, and Shell-Koppers). The former are applicable to Western subbituminous and lignite coal and the latter to practically all domestic reserves. Indirect liquefaction has been shown capable of average product costs that vary from $44.50/barrel to $59.40/barrel, depending on the methane, methanol, and M-gasoline product mix; consequently, it is possible that significant production could occur by the late 1980s.

Environmental impacts of conversion plants include atmospheric emissions (hydrogen sulfide, ammonia, particulate matter, hydrocarbons, sulfur dioxide, and hydrogen cyanide), water quality (suspended solids, ammonia, hydrogen sulfide, toxic metals, etc.), health impacts (suspected carcinogens and accidental discharges), ecosystems concerns (air and water emissions and product spills), and solid waste management issues (coal ash, coal refuse and waste treatment sludges). Landfills from solid waste disposal could require from 250 to 1,100 acres over a 20-yr period to dispose of the 1,000 to 4,500 tons of waste per day produced depending on the plant capacities and processes involved.

In addition to the previous procedures, coal conversion may be accomplished by underground gasification of thick seams (plus 50') at depths up to 3,300 ft (U.S. Department of Commerce 1979). Experimental designs involve increased seam permeability by chemical explosives, dewatering of the fracture zone, ignition by oxygen injection, steam-oxygen mixtures injection, collecting product gases, and upgrading these gases to commercial pipeline products. As in surface gasification processes, gasification pollutants derive from the materials created and released during reaction (hydrogen sulfide, ammonia, hydrogen cyanide, phenols, oils, etc.). By-produce water may contain tar, aromatics, olefins, thiophemes, light oil, and related compounds.

Additionally, any of more than 20 trace elements possibly contained in coal may be released in various forms during gasification (U.S. Department of Commerce 1979).

Several gasification plants are being considered for the study area and one is currently under construction near Beulah, North Dakota. The Great Plains Coal Gasification Association project will utilize the Lurgi process to produce high Btu gas at capital costs expected to be $1.4 billion; it will utilize approximately 4.7 mmt of lignite per year and is expected to be in operation by late 1984. Other projects are under consideration in New Mexico, Wyoming, Colorado and Utah (Coal Age 1980).

Power Plants

Power generation by steam electric-generating plants involves the direct combustion of coal, either in its raw state or after sizing and washing, to reduce sulfur content, ash and other impurities. The low sulfur content of Western coal has historically made it a desirable fuel for power generation due to stringent air quality requirements concerning sulfur emissions.

The alternatives of onsite generation with long distance transmission systems or transportation of coal to distant generation sites by rail or pipeline require recognition of the economic and environmental trade-offs.

The disadvantages of mine-mouth generation include the large water requirements for steam generation and cooling, atmospheric emissions (sulfur dioxide, nitrogen dioxide and particulates), prodution of large quantities of solid wastes (fly ash and bottom ash), waste water, and sanitary waste from the station. Combustion products contained in the flue gas include heat, carbon dioxide, water vapor, nitrogen oxides, sulfur dioxide, and inorganic noncombustibles. Appropriate air pollution laws and allowable limits for these potential air, water and solid waste pollutants are given in the environmental impacts section under land and land use.

Electrostatic precipitators may be used to remove suspended fly ash particles. Wet scrubbers may be used to wash SO_2 and particulates from flue gas by reaction with lime if required by the level of SO_2 emission. Demineralizers are required to remove dissolved solids for makeup water.

Solid fly ash and fly ash slurry must be disposed of in appropriately-sized land fills or possibly returned to the mine pit for burial. Leaching of chemical pollutants to the ground water table is a concern. Calcium sulfite from scrubbers may also become a significant solid waste problem.

Onsite generation may require 7 tons of water for each ton of coal consumed, as opposed to one ton of water required for the pipeline movement of an equivalent amount of coal. Thermal pollution concerns dictate that water for cooling must not be disposed of until cooled to a temperature nonharmful to aquatic life.

Carbon dioxide emissions are additionally harmful as they could raise ambient temperatures and allow increased solar radiation to reach the earth. Finally, sulfur and nitrogen dioxide may react with atmospheric moisture to create sulfuric and nitric acids (acid rain), harmful to vegetation, aquatic life, and to stone structures.

Other adverse impacts of onsite utilization that compound those of the mine site include land required for dumping; storage and loadout facilities; evaporation ponds and cooling towers; additional water for cooling; facilities for collection and disposal of fly ash, bottom ash, and scrubber sludge; additional atmospheric emissions from stacks and cooling towers; land requirements for transmission towers and rights of way; and potential harm from electromagnetic fields near transmission lines.

Offsite Transportation

Offsite utilization may involve transportation by pipelines, railroads, or barges. Each means is discussed individually below, recognizing that each means may be used in combination with others.

Pipelines

Coal slurry lines are currently controversial; they are viewed by proponents as vital for transportation of the increased production of compliance coals projected for the near future and as a means of minimizing increases in rail rates. Additionally, it is argued that: (1) pipelines use either water of little value (saline water) or water that is too expensive for other uses, (2) transport water can be used as cooling water at the point of use, (3) pipelines can navigate terrain too rugged for rail, and (4) pipeline construction is more cost-effective than expanding or upgrading rail lines.

Opponents feel that such lines would: (1) affect the profitability of the rail industry, (2) require excessive amounts of scarce water quantities, (3) create pollution hazards through breaks or ruptures, (4) cause pollution of streams receiving discharged slurry water, (5) require resolution of complex water rights issues, and (6) compete with other new water demands, as for coal gasification plants. Operational impacts on water quality are of major concern due to the potential for pollution by spills and leaks, pond failures, improper disposal of holding pond leachate, and slurry water disposal (Nugent 1981).

Facilities required include slurry preparation plants, gathering pipelines, pump stations, water supply and treatment facilities, distribution pipelines, tankage, and dewatering plants (Cauthen 1979). Each mile of pipeline corridor requires 12 acres of right-of-way while booster stations and water makeup ponds require from 10 to 30 acres (Nugent 1981).

Transmission technology is well understood and necessary equipment components are now available. Major design characteristics involve pipeline length, diameter, throughput, moisture content, coal specific gravity, percent solids, particle size, type of separator, flocculator use, and thermal and slurry heating methods. Engineering constraints on corridor selection include excavation costs, grades (15 to 20% maximum), rights-of-way sharing, and avoidance of environmentally sensitive lands, wildlife habitat, wetlands, parks and recreation areas.

A coal slurry line currently transports 5 mmt of coal annually from Black Mesa, Arizona, to Mohave, Nevada (275 mi). An additional line operated between Cadiz, Ohio, and Cleveland, Ohio, in 1963. At least eight additional lines are currently under investigation. Such lines vary in length from 100 to 1,500 mi with capacities from 1.3 to 45 mmt/yr (Coal Age 1980).

Railroads

Railroads supply the bulk of current coal transportation needs and originated more than 60 percent of all Western coal production in 1979. Most coal was hauled by rail to utilities. Other transport modes are currently less important to Western coal production. Trucks handled about 15 percent of Western coal tonnage, mainly for local markets in Utah and Colorado. About 2 percent of Western coal was moved by rail to port terminals on the Great Lakes, and another 4 percent to river connections. About 23 percent was moved by tramway, conveyor, or private railroad.

The Western rail transportation network has the ability to increase its capacity to move coal from mine to market through the 1990s. Most Federal coal leases are served by rail. The mine-to-market transportation cost of Western coal ranges from 10 to over 70 percent of delivered fuel costs and constitutes an important factor in determining future demand. The principal future constraint may be the willingness of the railroads to invest sufficient capital on a timely basis.

Most large-scale rail transport is by dedicated unit train service of approximately 90 to 110 cars of 90- to 100-t capacity. Twenty- to 50-mph speeds are attained, automated loading and unloading is utilized, and switching and yard delays are eliminated (U.S. Department of Commerce 1978). Advantages of rail transport include the current existence of trackage between most future points of extraction and use and service flexibility sufficient to meet varying production and consumption needs.

Disadvantages include an increasing cost of service, the use of a relatively high cost fuel, single purpose land use in rail corridors, noise pollution in populated areas, disruptive and frequent rail traffic through populated areas, possible vibratory structural damage to nearby buildings, a relatively high accident frequency rate, fire potential from sparks, and deposition of wind-loss coal along rights-of-way. Additionally, railroads are considered to be labor intensive with one study (Faddick 1979) showing personnel requirements of 2,570 individuals for the movement of 23 mmt/yr from Wyoming to Arkansas, as compared to 335 people for pipelines of similar capacity. Such requirements could add to the population influx to towns with a currently strained infrastructure.

The land required for railroad rights-of-way (17 to 34 m) is not greatly different than for slurry pipelines (25 m), but it is much less than for high voltage transmission lines (200 m).

Barges

Barge transport is of no direct consequence for the study area but could assume importance when used in combination with either rail or pipeline transport.

Presently 1,800 companies operate 4,400 towboats and 28,000 barges on a 25,000-mi river system that includes both coasts and the Mississippi river system (Faig 1981). Representative tow capacities range from 22,000 to 45,000 t and are a function of river depth, flow rate, water level, and lock size. Barge capacity is representative 1,500 t (195' X 35' X 12').

Advantages of barge transportation include minimal pollution, low cost, fuel efficiency, safety, less urban exposure, and large capacity. Disadvantages include lack of direct access routes, the need for interfacing with rail or truck haulage systems, and the current need to upgrade parts of the lock and dam system.

Barges handled 16 percent of total coal shipments in 1980 and 25 percent of that coal was transported to coking plants. Although most shipments involve coal from the Appalachian and midcontinent areas, any substantial shipment of Western States coal to Southern utilities could involve a combination of rail to the Mississippi River and barging to Southern points of use.

Comparative Operating Impacts

Many operational impacts have been noted qualitatively in the previous descriptions of activities required for the utilization of coal for power generation and coal conversion. The activity categories that create such impacts are coal exploration, plant development, extraction, beneficiation, transportation, conversion and utilization, and transmission and delivery.

Figure 2 shows the impact categories determined by the Department of the Interior for assessing alternative coal development strategies (DOI 1979). Such impacts are determined by specification of various regional coal production and consumption levels, allocation of such production quantities to the most likely mode of transportation, and multiplication of such quantities by impact multipliers that are based either on production or transportation units. These major operational impacts are subsequently used as input parameters to determine the sociologic and ecologic impacts.

Figure 3 provides comparative quantitative impacts for eight types of production and utilization facilities including a:

- 12 mmt/yr surface mine
- 12 mmt/yr underground mine
- 25 mt/dy beneficiation plant
- 3,000 mW power plant
- 250 mmscfd Lurgi coal gasification plant
- 250 mmscfd Dynathane coal gasification plant
- 250 mmscfd Synthane coal gasification plant
- 30,000 t/day SRC-II coal liquefaction plant

FIGURE 2. COAL DEVELOPMENT IMPACT FACTORS, COAL IMPACT ESTIMATION PROGRAM (CIEP)

Main Impact Factors		Socioeconomic Impact Factors	Ecological Impact Factors	
Air emissions:	Total suspended particulates	Indirect construction employment	Land disturbed:	Cropland
	Hydrocarbons	Indirect operational employment		Pasture
	Carbon monoxide	Dependents		Range
	Sulfur oxides	Total population		Forest
	Nitrogen oxides	School age children		Wetlands
	Carbon dioxide	Teachers		
		Classrooms	Productivity lost:	Corn
Water use:	Makeup (effluent and evaporative loss)	Physicians		Soybeans
		Hospital beds		Cotton
		Housing units		Wheat
Land disturbed:	Short term	Water treatment		Sugar beets
	Long term	Sewage treatment		Oats
		Solid wastes		Hay
Solid wastes:	Active (scrubber waste, treatment residuals, etc.)	Policemen		Grass
		Fireman		Timber
	Inert (ash, slag, rock, etc.)			Marshland
				Animal units
Accidents			Biota disturbed:	Mule deer
Fatalities				Antelope
Operating energy				Moose
Direct construction employment				Elk
Direct operational employment				Deer
				Small mammals
				Song birds
				Game birds
				Predators
				Reptiles

Source: DOI 1979.

Figure 3. COMPARATIVE INPUT-OUTPUT IMPACTS, CASE STUDY FACILITIES

Input/Output Factors	12 mmtpy Underground Coal Mine at Kaiparowits	2 mmtpy Surface Mine at Navaho	25,000 tpd Coal Beneficiation Plant	3,000 mW Power Plant at Gillette, Wyoming	250 mmscfd Lurgi Coal Gasification Plant at Coalstrip, Montana	250 mmscfc Dynthane Coal Gasification, Coalstrip, Montana	250 mmscfc Synthane Coal Casification, Coalstrip, Montana	30,000 tpd SRC-II Coal Liquefaction, Cillette, Wyoming
Input Requirements								
Manpower								
Construction	2,330 man-years	832 man-years	258 man-years	9,960 man-years		10,781 man-years	10,781 man-years	21,900 man-years
Operating	2,384 people	552 people	22 people	436 people		589 people	689 people	1,600 people
Materials and Equipment	Continuous miners--64 Loading machines--64 Ready-mixed concrete--92,000 tons Structural steel---6,000 tons Reinforcing bars---6,800 tons Piping---4,600 tons	Stripping shovels-----140 yd^3 Cement--62,800 tons Structural steel-----940 tons Draglines--10,400 tons		Refined products Ready-mix concrete Piping Steel Steam turbogenerators Boilers	72,000 tons 456,000 tons 13,000 tons 26,000 tons 4 million hp 28 billion Btu/hr	Structural steel-------14,000 tons Piping-----------------58,000 tons Ready-mixed concrete--180,000 tons	Structural steel-------14,000 tons Piping-----------------58,000 tons Ready-mixed concrete--180,000 tons	Fabricated steel--200,000 tons Concrete---------288,000 tons Refined products---50,000 tons
Economics								
Capital costs	$308 million	$104 million	$36.5 million		$880 million	$750 million	$750 million	$1.2 to $1.3 billion
Operating costs	$100 million	$46 million	$2.8 million/yr		$11 million	$9.8 million	$9.8 million	$219 million/year
Water	None	4,000 ac-ft/yr	1,400 gal/min		42,000 ac-ft/yr	9,263 ac-ft/yr	29,036 ac-ft/yr	4 mm gal/day (100% required)
Land	2,750 acres (given time) 36,000 acres (30 yr)	20,000 acres (30 yr) 240 acres (at one time)	90 acres		2,400 acres	800 acres	800 acres	1,800 acres
Auxiliary Energy	3.5×10^4 Btu/yr	55×10^6 kWhr/yr electricity 1.8×10^6 gal/yr, diesel	1.7×10^6 Btu/day		None			41 mW
Outputs								
Air Emissions	Particulates----0.35 ton/day Hydrocarbons--144 tons/day	Particulates--1,700 lb/hr Hydrocarbons------8 lb/hr SO_2---------------8 lb/hr NO_x-------------100 lb/hr CO---------------23 lb/hr CO_2-----------5,500 lb/hr	7 lb/hr		Particulates------14 ton/day SC_x---------------77 ton/day NO_x--------------316 ton/day CO----------------18 ton/day HC-----------------5 ton/day Aldehydes----------0.1 ton/day CO_2-----------76,800 ton/day	Particulates----------Negligible SO_2--------------------516 lb/hr NO_x--------------------495 lb/hr HC---------------------953 lb/hr CO--------------------Negligible	Particulates-------------8 lb/hr SO_2-----------------3,524 lb/hr NO_x-----------------5,052 lb/hr HC------------------1,047 lb/hr CO--------------------176 lb/hr	Particulates------475 lb/hr SO_2--------------248 lb/hr Total organics--1,067 lb/hr CO---------------126 lb/hr NO_x------------1,280 lb/hr NH_3---------------12 lb/hr CO_2-----------858,000 lb/hr
Water Effluents	Site dependent	Recycled	None		2,096 ac-ft/yr to zero discharge evaporation ponds	310 gal/min--ash ponds 820 gal/min--evaporation ponds	310 gal/min--ash ponds 820 gal/min--evaporation ponds	Negligible
Solid Wastes	78 tons/day	Returned to mine	8,000 tons/day		Ash-----1,974 ton/day FGD sludge--1,488 ton/day	Ash-----------------225,000 lb/hr Water treatment sludge---500 lb/hr Spent catalyst--------Intermittent	Ash-----------------180,000 lb/hr Limestone sludge-----110,000 lb/hr Spent catalyst--------Intermittent	2,500 tons/day
Noise	Insignificant	Insignificant	Negligible		Minimal	Negligible	Negligible	Negligible
Occupational Health and Safety								
Fatalities	7.2 deaths/yr	0.6 deaths/yr	0.56 deaths/yr		0.77 deaths/yr	0.45 deaths/yr	0.45 deaths/yr	0.32 deaths/yr
Injuries	370 injuries/yr	19 injuries/yr	11 injuries/yr		3.2 injuries/yr	15 injuries/yr	15 injuries/yr	6.2 injuries/yr
Lost man-days	210 man-days/yr	1300 man-days/yr	4,900 man-days/yr		1,200 man-days/yr	4,200 man-days/yr	4,200 man-days/yr	1,494 man-days

Source: Wayman and Genasci 1980.

The comparative differences between the various costs shown are considered valid, although the absolute costs are expressed in 1974 dollars. Although several of the sites are not in the immediate study area, they are in Western States with similar environmental and resource concerns and characteristics.

Figure 3 demonstrates some notable differences in environmental impacts of extraction and beneficiation facilities as compared to coal utilization facilities.

It shows relatively small manpower, materials and equipment needs, capital and operating costs, and water requirement inputs for mining and beneficiation facilities relative to similar requirements for utilization facilities. Additionally, air emission, water effluent and solid waste outputs were much less for mine and beneficiation facilities than for utilization plants. However, land requirements and ancillary energy inputs were larger over time (although not any specific point in time) for mines and beneficiation plants, and occupational health and safety experience was approximately the same.

A clear trade-off appears to exist for onsite facilities between the advantages of greatly increased long- and short-term employment levels, the economic spinoffs of high capital expenditures, and the greatly increased demands for water and land versus the increased levels of atmospheric emissions, the substantial generation of solid wastes, and the need for significantly larger areas of land.

Figure 4 shows selected salient design parameters as well as land requirements and operating impacts of the mine-mouth complex of the Falkirk Mining Company, a wholly owned subsidiary of North America Coal Corporation, and the Coal Creek Generating Station of the Cooperative and United Power Associations. The complex, located near Underwood, North Dakota, supplies power to both Minnesota and North Dakota facilities. Figure 4 further quantifies many of the processes and facilities and the impact matrices described in previous sections.

ENVIRONMENTAL IMPACTS

In addition to evaluating the purely economic aspects of offsite versus mine-mouth locations for power generating stations, it is important to evaluate the environmental aspects of the various options. This section summarizes and compares environmental aspects of offsite and mine-mouth power generation and includes environmental impacts which may result from the construction and operation of coal-fired steam electric and coal gasification power plants as well as the means of conveying the energy from the mine site to an offsite location.

Specific data regarding the physical and biological environments of alternative power plant locations is necessary to present direct comparisons of environmental impacts. Because the analysis of possible environmental impacts presented herein is generic rather than site-specific, direct comparisons of

FIGURE 4. - SUMMARY OF SALIENT FEATURES, FALKIRK MINE AND COAL CREEK GENERATING STATION UNDERWOOD, NORTH DAKOTA

MINE

Reserves

- 310 million tons lignite
- Analysis - 6,475 Btu/lb.
  - Moisture, 38%
  - Ash, 8%
  - Sulphur, 8.6%
  - Sodium Oxide, 1.9%

Design

- Planning initiated, 1973
- Development, 1975
- Deliveries, 1978
- Ultimate capacity, 5.6 mmt/yr

Activities

- Topsoil/subsoil removal, 44 yd^3 scrapers
- Overburden removal, 2 to 105 yd^3 draglines
- Partings and reclamation, 17 yd^3 dragline

Loading and Hauling

- Seam ripping, dozers, 8' ripper
- 2 to 19 yd^3 electric shovels
- 20 yd^3 front-end loaders

MATERIALS - HANDLING AND STORAGE

Hauling

- 160-ton trucks

Materials Handling

- 2 to 400 ton conical bins @ truck dump
- Primary crushers - 10" X 0"
- Secondary crusher - 1 1/2" X 0"
- Conveyor - 4,000 t/hr, 72" wide, to 16,000-ton silo
- 2,500 t/hr, 1-mi belt to plant

Plant Storage

- 800-t/hr coal feed rate
- 1 mmt inactive storage, mobile equipment and stacker reclaim
- 126,000 tons active storage, stacker reclaimer
- 48,000 tons live storage, 3 silos
- Automatic blending, mine and storage

FIGURE 4. (Continued)

PLANT

Boilers
- 2 unit, 1100-mW balanced draft @3.7 mlb/hr @2,620 psig and 1,005° F
- Pulverized lignite

Water
- 15,000 ac-ft annually @14,300 gpm
- 7-mi transfer, river to plant
- 35-ac water storage basin of 860 ac-ft capacity
- Zero water discharge - 2 evaporator ponds, 2 mi from plant, 114 surface acres
- Raw river make-up water

Cooling Towers
- 3 towers, 225-ft diameter, 42-ft height
- 9 ac, 190 ac-ft basin
- Closed system

Electrostatic Precipitators
- 99.5% particulate removal

Scrubbers
- 6.3 mlb fluegas/hr
- 5,000 to 14,000 lb SO_2/hr
- 135° F stack output
- 60% fluegas scrubbing, 40% fluegas for reheat

Demineralizers
- 650 gpm
- 2 - 325,000 gal storage tanks

Ash Disposal
- 105 acres @ 3,400 ac-ft bottom ash, scrubber sludge

TRANSMISSION

Lines - DC
- 400 kVdc
- Bi-polar, 2 conductor/pole
- Self-supporting, lattice steel, @ 1,400-ft spacing
- 35- to 50-ft ground clearance
- 430 mi, North Dakota to Minnesota

Lines - AC
- 230 kV, 5 mi to existing lines, 12.5 mi to existing plant
- 69 kV line to mining operations

Source: Murray 1982; Lignite Technology 1980.

environmental impacts of mine-mouth and offsite power plants are difficult. Consequently, this section presents a listing of environmental impacts that may or may not be critical in an analysis of various power plant siting options and a short discussion of the environmental issues identified.

The discussion of environmental impacts will be divided into two categories; (1) impacts associated with fuel or power conveyances, and (2) impacts associated with power plants. For mine-mouth power plants, there are two types of conveyances which move energy from the power plant to offsite locations: (1) steam electric power plants use electrical power transmission lines to convey electricity offsite, and (2) coal gasification plants convey gas offsite by pipline.

For offsite power plants, coal must be transported from the mine to the offsite power plant. In the study region, the means of conveying coal to offsite power plants are train, coal slurry pipeline, and truck.

In considering impacts associated with mine-mouth and offsite power plants, two types of power plants are considered: (1) coal-fired steam electric power plants and (2) coal gasification plants. Both of these power plants may be utilized at mine-mouth and offsite locations. Strictly speaking, coal gasification plants are not "power plants"; however, they will be considered under the general heading of power plants in the discussion of environmental impacts.

In many cases, a direct environmental impact may cause other environmental impacts which are referred to as secondary impacts. For example, burning coal at a steam electric power plant may elevate the concentrations of certain air pollutants (a primary environmental impact) which in turn may adversely affect nearby plant and animal communities (a secondary impact). The emphasis of this section is on primary environmental impacts because assessing secondary impacts is more speculative than assessing primary impacts. However, secondary impacts should be considered when the impacts of various power plant siting options are being evaluated.

Air Quality

Regulations

Air quality is a critical environmental issue related to the operation of coal-fired power plants; consequently, there are regulations which govern power plant emissions. The two major sets of air pollution regulations which apply to coal-fired power plants are the New Source Performance Standards (NSPS) for steam electric power plants, and the Prevention of Significant Deterioration (PSD) regulations which must be complied with prior to issuing a permit to conduct power plant operations.

The NSPS regulations promulgated by the EPA in June of 1979 gave performance standards (See Table 2) for the emission of particulates, sulfur oxides (SO_x), nitrogen oxides (NO_x), and opacity at new power plants. Both a maximum emission limit (lb/mm Btu) and a percentage reduction are specified

TABLE 2.

NEW SOURCE PERFORMANCE STANDARDS[a] - SOLID FUELS

	Particulate	SO_x	NO_x
Reduction of uncontrolled emissions (%)	99+[b]	90-70[cf]	65[bc]
Maximum emission limits ($lb/10^6Btu$)	0.03	1.2[c]	0.5-0.8[e]
Opacity	20%[d]		

[a] EPA final NSPS (June 1979).

[b] Percent reduction requirements are not controlling; compliance with emission limit will ensure compliance with percent reduction.

[c] Compliance based on 30-day rolling average.

[d] Averaging time is 6 minutes. Opacity limit is not controlling when all other regulations are complied with.

[e] Subbituminous coal = 0.5 lb/mBtu heat input
Any other solid fuel = 0.6 lb/mBtu heat input
Lignite coal = 0.8 (25% or more feed to a slag-tapping furnace by weight of lignite mined in North or South Dakota or Montana)

No emission limitation if the fuel contains more than 25%, by weight, coal refuse.

[f] 90% reduction required at all times except when emission is less than 0.6 lb/mBtu. When SO_2 emissions are less than 0.6 lb/mBtu heat input, a 70% reduction in potential emissions is required.

(Electric Power Research Institute 1981a) for all but SO_x. Compliance with the maximum emission limit usually ensures compliance with the percentage reduction requirements (Joseph 1982).

The PSD regulations detail allowable increases of certain air quality parameters over baseline conditions. Baseline concentration refers to the ambient air quality as of August 7, 1977, for particular geographic regions; based upon existing land use and air quality, these regions are classified as Class I, II, or III. National parks, wilderness areas, and other areas for which high air quality is an essential item contributing to the use value of the region are classified as Class I. Other regions in which air quality is not essential to the use value of the region are classified as Class II or III. Power plants which may affect Class I regions must meet more stringent air quality requirements than those which may affect only Class II or III areas. The PSD maximum allowable increases for particulates and sulfur dioxide for Classes I, II, and III are shown in Table 3.

Evaluation of Environmental Impacts

Table 4 summarizes impacts to air quality that may result from constructing and operating mine-mouth and offsite power plants and conveying energy offsite. It includes estimates of the degrees to which particular impacts are critical; these estimates are included for guidance; however, in particular cases, certain environmental issues may be more or less critical than indicated in Table 4.

Conveyances

For offsite power plants, the primary means of conveyance in the study region are coal slurry pipeline, train and truck. For mine-mouth power plants, energy may be conveyed offsite by either powerline or pipeline. All of the above means of conveyance have one common air-related environmental problem: fugitive dust emissions. Fugitive dust may be emitted to the air during the construction of coal slurry pipelines, new railroad spurs, new access roads (all associated with offsite power plants) and gas pipelines and powerlines (mine-mouth power plants). These emissions are considered to be a minor temporary environmental impact, and those associated with construction of conveyance facilities are probably less in humid parts of the country than in the semiarid study region.

Particulate and gaseous pollutants will be emitted by railroad locomotives and trucks and by construction equipment during the building of all conveyance facilities. Those pollutants associated with construction activities are considered very minor and temporary. The increased emissions by truck and train sources will continue as long as they are used to transport coal to offsite power plants; their impact depends upon ambient air quality and the number and types of locomotives and trucks required to haul coal to offsite locations.

The operation of powerlines may generate ozone, which when in excess, may cause health problems, but the amount of ozone emitted by powerlines generally is not considered to pose a significant health hazard.

TABLE 3.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) STANDARDS

	Maximum Allowable Increase (Mg/M^3 of Air)		
	Class I	Class II	Class III
Particulate Matter			
Annual Mean	5	19	37
24-hr Maximum	10	37	75
Sulfur Dioxide			
Annual Mean	2	20	40
24-hr Maximum	5	91	182
3-hr Maximum	25	512	700

Notes:

1. Reference 40 CFR 51, Prevention of Significant Air Quality Deterioration, FRP 26380, June 19, 1978.
2. For any period other than the annual period, the applicable maximum allowable increase may be expected during one such period program at any location.
3. Class I area indicates parks and wilderness areas greater than 5,000 to 6,000 acres; Class II and Class III indicate all other areas.

TABLE 4.

AIR QUALITY IMPACTS

Case	Impact
I. Offsite Power Plant	
A. Conveyances	
1. Coal Slurry Pipeline	(1) Construction of the pipeline may cause fugitive dust emissions (L, M).
2. Train	(1) Increased rail traffic may increase the emission of dust and gaseous pollutants to the air (M).
3. Truck	(1) Increased truck traffic may increase the emission of dust and gaseous pollutants to the air (M).
B. Power Plant	(1) Vehicular travel, blasting, grading, and wind erosion may cause fugitive dust emissions (L).
	(2) Operating vehicles & machinery may cause gaseous and particulate emissions (M).
	(3) Burning of coal causes gaseous, particulate, and radioactive emissions (L).
	(4) Cooling of boiler reject water may cause local thermal pollution of air (L).
II. Mine-Mouth Power Plant	
A. Conveyances	
1. Gas Pipeline	(1) Construction of the pipeline may cause fugitive dust emissions (L, M).
2. Powerline	(1) Construction of the powerline may cause fugitive dust emissions (L, M).
	(2) Operation of powerlines may cause ozone emissions (M).
B. Power Plant	(1) Vehicular travel, blasting, grading, and wind erosion may cause fugitive dust emissions (L).
	(2) Operating vehicles & machinery may cause gaseous and particulate emissions (M).
	(3) Burning of coal causes gaseous, particulate, and radioactive emissions (C).
	(4) Cooling of boiler reject water may cause local thermal pollution of air (L).

KEY:
C = Critical Impact
M = Minor Impact
L = Local Impact

Power Plants

Air quality problems associated with power plant emissions are considered more critical than those associated with conveyances. The air quality parameters emitted by both mine-mouth and offsite coal-fired power plants which pose known environmental problems are SO_x, NO_x and particulates. Coal gasification plants generate the same general types of air pollutants as coal-fired power plants. The emission rates for a proposed combined Lurgi process gasification plant and an 880-mW coal-fired electric power plant burning lignite from the Beulah-Hazen coalfield in North Dakota are presented in Table 5 (U.S. Department of Energy 1980)

Certain trace elements, including radioactive materials such as uranium and radon gas, are emitted from coal-fired power plants. The type and amount of trace element emissions from power plants have only recently been studied (U.S. Environmental Protection Agency 1977, North Dakota State Department of Health 1977).

Because the efficiency of steam electric power plants is directly proportional to the difference between the water temperature as it enters the turbine and the temperature as it leaves the turbine, all power plants must have a means of rapidly cooling large quantities of water. If wet or dry cooling towers are used, the air quality is affected locally. Wet cooling towers add such great amounts of water vapor to the air that excessive fog and frost may occur in the plant vicinity. The use of dry cooling towers may create an area of elevated air temperature with consequent local weather effects.

Differences between plant size, process, and air pollution control technologies probably account for greater differences in air quality impacts than the difference between mine-mouth and offsite power plant locations. However, the choice of mine-mouth versus offsite power plant locations may cause differences in air quality impacts in a few ways.

First, because many parts of the study region are classified as PSD Class I areas, power plants in and near these areas may be required to implement more comprehensive air pollution control programs to meet the stringent Class I standards than those in other areas. Consequently, allowable overall air quality impacts may be less in Class I areas than other areas.

Certain air quality standards for coal mines may be relaxed in the near future. However, it is probable that the standards for Class I areas will remain intact while those for other areas will be relaxed. If this occurs, the differences in air quality impacts between regions near Class I areas and other regions will be pronounced (Joseph 1982).

Air pollution dispersal mechanisms such as wind speed and mixing height vary from region to region. However, plant design features such as smokestack height and air pollution control devices usually compensate for the regional variation in natural air pollution dispersal mechanisms.

TABLE 5.

EMISSION RATES FROM PROPOSED GREAT PLAINS GASIFICATION PROJECT (GASIFICATION PLANT AND 880 MW COAL-FIRED POWER PLANT)

Parameter	Coal Gasification Plant Emission Rate (lb/hr)	880 MW Coal-Fired Power Plant Emission Rate (lb/hr)
NO_x	1,100	4,934
SO_2	2,825	11,832
SO_3	-	438
Total Suspended Particulates	265	424
CO	364	1,135
HC	140	-
Arsenic	-	7.50
Cadmuim	-	0.02
Flourine	-	9.60
Lead	-	8.00
Mercury	-	0.24
Selenium	-	1.40

Source: U.S. Department of Energy 1980.

Finally, the presence of excessive moisture or heat which may result from using wet or dry cooling towers may be regarded as a benefit in certain parts of the country and an adverse impact in other areas. For example, much of the semiarid study region may welcome the additional moisture provided by wet cooling towers, while the added moisture may be considered an adverse impact in a city located in a humid area.

There are several secondary impacts which may result from the primary air pollution impacts discussed above. These are listed below:

- Elevated concentrations of many pollutants, including SO_x, NO_x, and particulates, are known to have adverse impacts on plants and animals (U.S. Department of Energy 1980).
- Most pollutants which enter the air via burning coal at power plants eventually become mixed with soils or water at the earth's surface. The impacts which result from such mixing are poorly understood (U.S. Bureau of Land Management 1982).
- The emission of sulfur and nitrogen oxides to the atmosphere causes an increase in the acidity of rainfall. Such rainfall may adversely affect life and enhance weathering of manmade structures, soil, and rock. Because soils in the study region are generally alkaline and deep, burning coal in the study region should not produce adverse impacts within the region; however, impacts to other regions are uncertain (U.S. Bureau of Land Management 1982).

Water

Water Supply

Table 6 summarizes impacts to water supply that may result from constructing and operating mine-mouth and offsite power plants and conveying energy offsite. The degree to which impacts pose critical water supply problems is estimated in Table 6. In particular cases, water supply impacts may be more or less critical than indicated in Table 6.

Conveyances.

The primary means of energy conveyance for mine-mouth and offsite power plants have been identified in preceding sections. No water supply impacts were identified for powerlines and pipelines needed to convey electricity or gas from mine-mouth power plants to offsite locations. For offsite power plants, no water supply impacts were identified for train or truck transportation of coal.

TABLE 6.

WATER SUPPLY IMPACTS

Case	Impact
I. Offsite Power Plant	
A. Conveyances	
1. Coal Slurry Pipeline	(1) Use of water for slurry depletes local ground or surface water supplies (C).
2. Train	No Impacts Identified.
3. Truck	No Impacts Identified.
B. Power Plant	(1) Consumptive use of water may deplete local water supplies (C). (2) Paving of ground surface at plant site may locally increase the amount and timing of surface water flows and decrease ground water recharge (M, L).
II. Mine-Mouth Power Plant	
A. Conveyances	
1. Gas Pipeline	(1) No Impacts Identified.
2. Powerline	(1) No Impacts Identified.
B. Power Plant	(1) Consumptive use of water may deplete local water supplies (C). (2) Paving of ground surface at plant site may locally increase the amount and timing of surface water flows and decrease ground water recharge (M, L).

KEY:
C = Critical Impact
M = Minor Impact
L = Local Impact

Coal slurry pipelines may be expected to affect local ground or surface water supplies because large amounts of water are needed to form the slurry in which the coal is transported. The slurry mixture in coal slurry pipelines is typically 50 to 55 percent water by weight. Water requirements for a coal slurry pipeline supplying a 1,000 mW coal-fired power plant are estimated to be about 2.5 cfs or 1,800 ac-ft/yr (Electric Power Research Institute 1981b).

The water use impacts of coal slurry pipelines may be mitigated by either utilizing water that is unsuitable for other uses (for example, saline water) or recirculating the water from the pipeline terminus to the source. The major problems associated with these two options are corrosion of metal parts and high cost, respectively.

In summary, the water supply impacts of energy conveyance may differ from mine-mouth power plants to offsite power plants. Where the proposed means of transporting coal to an offsite power plant is slurry pipeline, local water supplies may be depleted. Water supplies should not be affected when powerlines or pipelines are used to transport electricity or natural gas from a mine-mouth power plant to offsite locations.

It is probable that very minor amounts of water will be required to construct, operate, and maintain all energy conveyance facilities. However, such minor usage would probably not significantly affect water supplies.

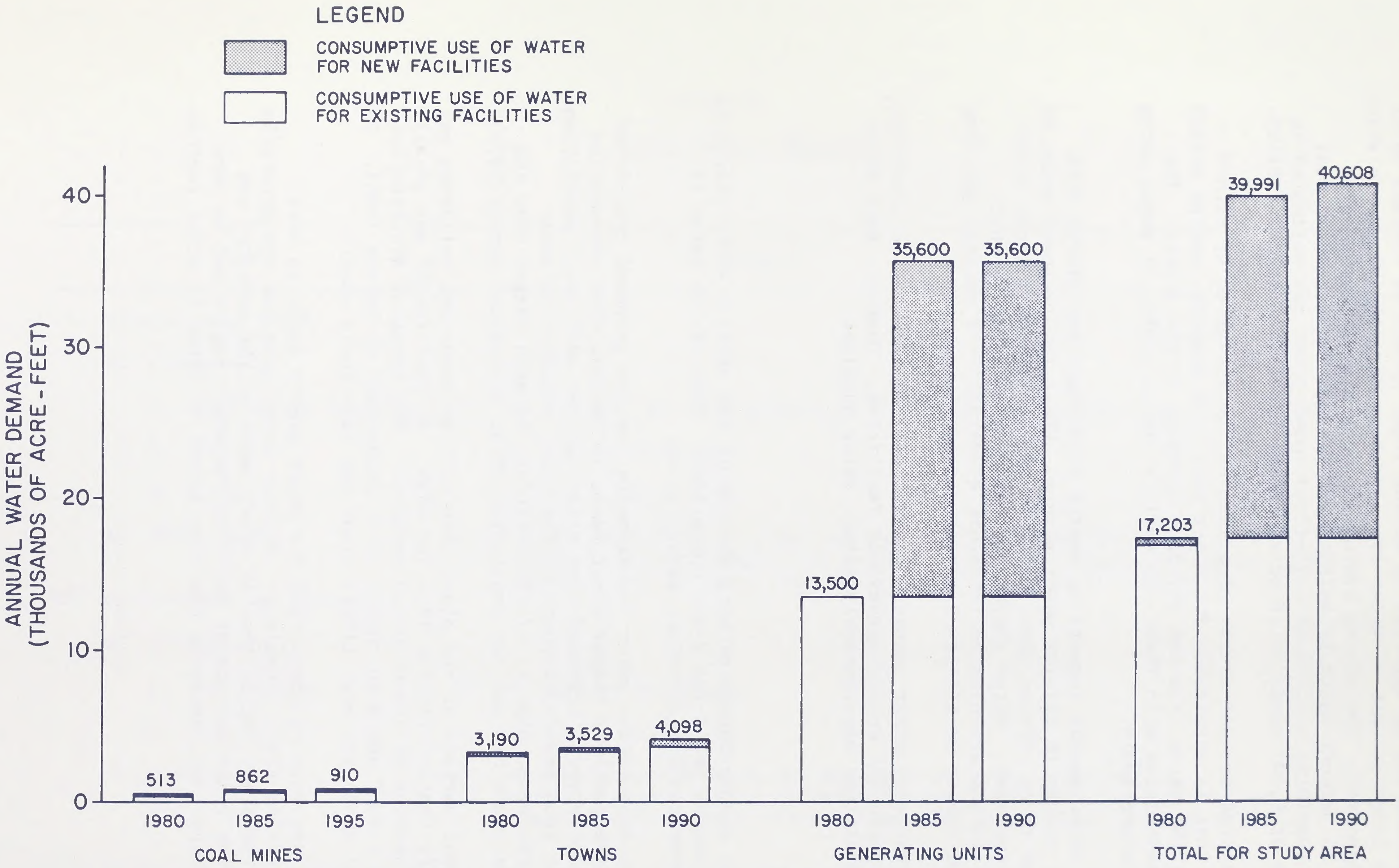
Power Plants.

The primary water supply impact of both mine-mouth and offsite power plants is the consumptive use of water for plant operations. Most of the water is consumed during the cooling of boiler reject water.

Figure 5 compares consumptive water requirements for two proposed coal-fired power plants in the northern Powder River Basin in Montana with consumptive use requirements of several proposed coal mines and the additional population that would result from new developments. The total consumptive water requirement for the power plants, 22,100 ac-ft/yr, is much larger than the water used by the new mines and new population (U.S. Geological Survey 1979).

Covering the ground surface at the plant site with pavement and buildings may alter water supply characteristics in a few ways. Surface runoff may locally increase at the expense of ground water recharge. The temporal distribution of surface water runoff may also change (U.S. Department of Energy 1980). The impacts discussed above are most likely minor and relatively local.

All of the water use impacts identified for power plants apply to both mine-mouth and offsite plant locations. Because water supplies are generally more limited in the study region than in other parts of the country, the impact of consuming large amounts of water in the study region may be more severe than the impact of consuming the same amount of water in other regions.



SOURCE : U. S. GEOLOGICAL SURVEY (1979)

Figure 5. Estimated consumptive use of water, Northern Powder River Basin region.

Water Quality

Table 7 summarizes water quality impacts which may result from constructing and operating mine-mouth and offsite power plants and conveying energy offsite. Estimates of the degree to which impacts pose critical water quality problems are included for general reference. However, in particular cases, water supply impacts may be more or less critical than indicated in Table 7.

Conveyances

The primary means of energy conveyance for mine-mouth and offsite power plants have been identified in previous sections. The only water quality impacts associated with the conveyance of coal to an offsite power plant result from utilizing coal slurry pipelines.

Because chemical constituents in the coal leach into the slurry water, the water quality of the slurry water changes as it moves through the pipeline. Limited experimental evidence indicates that the concentration of total dissolved solids, sulfate, and metals increases and alkalinity and pH decrease in coal slurry water as it moves through the pipeline (Electric Power Research Institute 1981b). Because poor quality water may be used for the slurry pipeline and water quality decreases as the slurry moves through the pipeline, the disposal of slurry water at the pipeline terminus may pose a water quality problem. In addition, pipeline spills which may occur may adversely affect ground water quality.

An additional minor water quality impact associated with energy conveyance to offsite power plants is that construction of pipeline crossings at surface water bodies may increase suspended sediment concentrations in the water bodies. Construction of railroads and roads may also increase suspended sediment concentrations in nearby surface water bodies, but construction of additional transportation routes between the mine and offsite power plant will probably be minimal.

For mine-mouth power plants, no water quality impacts were identified for the construction and operation of powerlines used to transmit electricity offsite. If the mine-mouth power plant is a coal gasification facility, the construction of gas pipeline crossings at surface water bodies may increase suspended sediment loads to those water bodies.

Power Plants

Several water quality impacts may result from the construction of offsite and mine-mouth power plants. During the construction of power plants, changes in site drainage and earthwork activities may increase suspended sediment and salt loads to nearby streams. This impact depends upon site topography and rainfall and soil characteristics.

The major waste products created from burning coal to produce electricity or gas are bottom ash and fly ash. Another waste product, scrubber sludge, is produced from air pollution control systems. These waste products are usually disposed at or near the power plant. Leachate generated by these wastes may affect water quality in ground water systems. Primary water quality problems associated with these wastes are pH and metals.

TABLE 7.

WATER QUALITY IMPACTS

Case	Impact
I. Offsite Power Plant	
A. Conveyances	
1. Coal Slurry Pipeline	(1) Coal slurry spills which may occur may locally affect water quality (L).
	(2) Disposal and storage of saline or contaminated slurry water may adversely affect water quality (C).
	(3) Construction of pipeline crossings at surface water bodies may increase suspended sediment and salt loads in surface waters (L, M).
2. Train	(1) No Impacts Identified.
3. Truck	(1) No impacts Idenfitied.
B. Power Plant	(1) Site drainage changes, earthwork activities, and paving of ground surface may alter suspended sediment and salt loads in streams draining the site(?).
	(2) Disposal of ash & scrubber sludge may affect water quality in ground waters(?).
	(3) Cooling of boiler reject water may cause local thermal pollution of surface waters (L).
II. Mine-Mouth Power Plant	
A. Conveyances	
1. Gas Pipeline	(1) Construction of crossings at surface water bodies may increase suspended sediment loads in streams (M).
2. Powerline	(1) No Impacts Identified.
B. Power Plant	(1) Site drainage changes, earthwork activities, and paving of ground surface may alter suspended sediment and salt loads in streams draining the site (?).
	(2) Disposal of ash & scrubber sludge may affect water quality in ground waters (?).
	(3) Cooling of boiler reject water may cause local thermal pollution of surface waters (L).

KEY:
C = Critical Impact
M = Minor Impact
L = Local Impact
? = Undefined Extent

As mentioned in the air quality section, boiler reject water must be cooled to maximize the amount of electricity generated per unit of coal burned. A common means of cooling is to draw water from a nearby surface water body and pass it back to the surface water body after cooling the boiler reject. The water passed back to the river or lake is much hotter than that drawn from the water body; consequently, passing the heated water back to the water body causes local thermal pollution, which may adversely affect aquatic ecosystems.

The water quality impacts identified for power plants are the same at mine-mouth and offsite power plant locations. Water quality problems associated with the disposal of ash and scrubber sludge may be less critical at mine-mouth power plants than offsite power plants; the low rainfall and high evaporation rates in the study region cause less leachate formation and migration than would occur in more humid regions. The degree to which the other impacts identified are critical depends on factors such as baseline water quality and water pollution dispersal rates. No generalizations can be made about how baseline water quality and water pollution dispersal rates vary between mine-mouth and offsite power plant locations.

Land and Land Use

Table 8 summarizes land and land use impacts which may result from constructing and operating mine-mouth and offsite power plants and conveying energy offsite. The degree to which impacts are considered critical is estimated in Table 8. However, in particular cases, water supply impacts may be more or less critical than indicated in the table.

Land and land-use impacts fall into either of two categories: (1) a change in land use due to construction of conveyance or power plant facilities, or (2) change in soil characteristics and erosion rates. As an example, if the power plant site had been used as rangeland, construction of the power plant would cause a change in land use to industrial land use. Changes in land use may result wherever new facilities are built.

Changes in soil characteristics and erosion rates may occur as a result of earthwork activities at a construction site. Heavy equipment may compact the soil, resulting in an increase in overland runoff and erosion rates and a decrease in plant productivity. Scalping topsoil may expose subsoils which are generally less able to support vegetation and which may exhibit different erosion and runoff characteristics than topsoils. Removing vegetation may also increase overland runoff and erosion rates.

Conveyances

The presence of pipelines and powerlines associated with mine-mouth power plants and coal slurry pipelines, new roads, and new railroad spurs (associated with offsite power plants) probably causes a change in land use from what existed before construction of these facilities. Because new road and railroad construction would probably be minimal for most offsite power plant scenarios, the land use impact of these conveyances would probably be

TABLE 8.

LAND AND LAND USE IMPACTS

Case	Impact
I. Offsite Power Plant	
A. Conveyances	
1. Coal Slurry Pipeline	(1) Presence of pipeline causes a change of land use along the pipeline corridor (M). (2) Erosion rates may increase during the revegetation period which follows pipeline construction (M).
2. Train	(1) Presence of new rail spurs causes a change in land use along railroad right of way (M).
3. Truck	(1) Presence of new access roads causes a change in land use along right of way (M).
B. Power Plant	(1) Presence of the power plant causes a change in land use at the site (M). (2) Change in soil characteristics and erosion rates at the plant site may result from construction activities (M).
II. Mine-Mouth Power Plant	
A. Conveyances	
1. Gas Pipeline	(1) The presence of the pipeline causes a change in land use along the pipeline corridor (M). (2) Construction of the pipeline may cause an increase in erosion during the revegetation period that follows construction (L).
2. Powerline	(1) The presence of the powerline causes a change in land use along the right of way (M).
B. Power Plant	(1) The presence of the plant causes a change in land use at the plant site (M). (2) A change in soil characteristics and erosion rates at the plant site may result from construction activities (M).

KEY:
C = Critical Impact
M = Minor Impact
L = Local Impact

minimal. The land use impacts of pipelines and powerlines would be similar because extensive construction would probably be required, and both are essentially linear features.

Land use impacts associated with the construction of pipelines and power lines may be reduced by locating these features along existing highways, railroads, and property lines. Greater land use impacts result where pipelines and powerlines cross individual land use blocks such as farms or urban areas.

Soil characteristics and erosion rates may be affected by construction if construction activities disturb large parcels of ground. Very minor ground disturbance will occur at powerline construction sites and new roads and railroads, so soil impacts associated with such construction should be very minimal. Construction of a coal slurry pipeline to convey coal to an offsite power plant and construction of a gas pipeline to convey gas from a mine-mouth gasification plant to offsite locations may significantly affect soils because pipelines are commonly buried. Disturbance of the soil which occurs during excavation and burial of the pipeline may cause a change in erosion and runoff rates and a decrease in the ability to support vegetation. Erosion rates will probably be greatest during the revegetation period.

Because trains and trucks are the most common means of transporting coal to offsite power plants and land and land use impacts resulting from using these conveyances are considered minimal, the land and land use impacts of energy conveyance to offsite power will generally be less than impacts that result from energy conveyance from a mine-mouth power plant. Factors which influence land and land use impacts are specific conveyances used, the location of conveyances, and the extent to which new conveyances must be built.

Power Plants

The construction and operation of mine-mouth and offsite power plants may cause both a change in land use and change in soil characteristics. The change in land use occurs when the land use at the power plant site had been other than industrial before the power plant was built.

Soils at the plant site may be compacted by heavy equipment, scalped or excavated, and cleared of vegetation. The resulting soil impacts may be increased erosion, and both a change in the ability to generate runoff and the ability to support vegetation. These impacts may not be critical during the period of time the power plant is in use; however, soil impacts might be considered critical for portions of the plant site proposed to be reclaimed and used for other purposes such as grazing or agriculture.

Soils in humid portions of the country are more easily revegetated and reclaimed than those in the semiarid study region. If offsite power plants being considered are in humid regions, the land and land use impacts may be less severe than those associated with mine-mouth power plants.

The degree to which changes in land use are critical depends upon what the existing land use is at proposed power plant locations. Site-specific data are required to make this evaluation; no general difference between land use impacts resulting from mine-mouth power plants and land use impacts resulting from offsite power plants can be identified.

Biota

Table 9 presents a summary of the impacts to biota which may result from constructing and operating mine-mouth and offsite power plants and conveying energy offsite. Estimates of the degree to which impacts pose critical environmental impacts are given for general reference. However, in particular cases, impacts to biota may be more or less critical than indicated in Table 9.

Conveyances

The construction of new conveyances, including pipelines, roads, railroads, and powelines, affects terrestrial biota by eliminating or changing plant and animal habitats. Because most of the road and railroad network necessary for transporting coal from the mine to an offsite power plant will probably be in place, direct adverse impacts to plant and animal habitats resulting from road and railroad construction should be minimal. However, an increase in traffic along roads and railroads will cause increased noise, obstruction, and accidents, which may adversely affect humans and other animals. Typical effects range from avoidance and loss of habitat to loss of life.

Construction activities along pipelines and powerlines may cause a loss of plant and animal habitats or a change in habitats. The change is accomplished mainly by altering the numbers and types of vegetation along the right of way. The impact may be permanent where vegetation is periodically cut back or temporary where it is not maintained.

The impact of displacing animal habitats may be critical if the habitat is of limited extent or supports unique or endangered plant or animal species. Otherwise, impacts associated with habitat displacement along powerline and pipeline corridors are considered minor.

No general differences between the impacts on biota of conveyances associated with mine-mouth power plants and those of conveyances associated with offsite power plants were identified.

Power Plants

Similar types of impacts on biota may be expected at mine-mouth and offsite power plant locations. The major impact is the displacement of habitats which is caused by replacing native plant and animal species with the power plant. The degree to which this impact is critical depends upon the type and number of plant and animal species present at the site compared with their distribution elsewhere.

No general differences between the impacts on biota of mine-mouth power plants and the impacts on biota of offsite power plants can be identified. Site-specific information regarding species composition is necessary to evaluate differences in impacts to those species.

TABLE 9.

IMPACTS TO BIOTA

Case	Impact
I. Offsite Power Plant	
A. Conveyances	
1. Coal Slurry Pipeline	(1) Construction of pipeline causes loss of vegetation and displacement of plant and animal habitats (M).
2. Train	(1) Increase in rail traffic causes increased noise, obstruction, and accidents, which may adversely affect humans and other animals (M).
3. Truck	(1) Increase in road traffic causes increased noise, obstruction, and accidents, which may adversely affect humans and other animals (M).
B. Power Plant	(1) Construction of power plants eliminates or changes plant & animal habitats (M). (2) Increased noise near plant vicinity may affect humans and other animals (L).
II. Mine-Mouth Power Plant	
A. Conveyances	
1. Gas Pipeline	(1) Construction activities and clearing of vegetation along pipeline corridor eliminates or changes plant and animal habitats (L, M).
2. Powerline	(1) Construction activities and clearing of vegetation along powerline right of way eliminates or changes plant and animal habitats (L, M).
B. Power Plant	(1) Construction of power plant eliminates or changes plant & animal habitats (M). (2) Increased noise near the plant vicinity may affect humans & other animals (L).

KEY:
C = Critical Impact
M = Minor Impact
L = Local Impact

Operational

This section discusses both the capital and operating economics for coal-fired electric generating facilities, as well as conversion facilities exemplified by the Lurgi coal gasification process. All costs are shown as finite numbers when in reality the reader should bear in mind that site-specific conditions could cause fluctuations from the numbers in this report by 25 percent or more. Nevertheless, the values shown herein represent a reasonable average of costs obtained from several projects and are presented as mid-1982 dollars.

Plant

Figure 6 illustrates expected costs for a 288-mmscfd Lurgi coal gasification facility. The type of coal feed impinges significantly on the capital and operating costs of such a conversion plant. A portion of the cost differential is attributable to the fact that a lower rank coal supply requires a greater tonnage delivered to the plant for a given output; additionally, however, lignite possesses an inherently high moisture content which must be reduced prior to feeding in the gasifiers, and this requires associated plant investment and increased mine production.

Under these conditions, a lignite-fired conversion facility could be expected to cost nearly $1.65 billion or roughly 45 percent more than a similarly sized plant fueled by subbituminous coal.

Annual operating costs for both plants are also given on Figure 6. Again, a lignite-fueled operation is more expensive, and direct operating charges will approach $110 million/year. On a percentage basis, constant dollar operating expenses for coal gasification facilities will approach 6.5 to 7.5 percent of capital costs, a figure that compares favorably with other large industrial complexes.

Figure 7 presents the capital costs for a range of sizes of power generating stations. Whereas industry in contemplating a rather standard size for coal gasification plants, electrical generation units can be designed over a wide range of capacities. An important line on this graph is the one depicting unit costs ($/kW). Generally, an approximation of total plant capital costs can be made by multiplying the unit cost (say, $1,000/kW at present) times the rated capacity. Thus, an 880 mW station would be expected to cost nearly $880 million complete. Annual direct operating expenses, using a factor of 7.0 percent, will likely total $60 million/yr. It should be mentioned that, relative to power generating facilities, the rank of coal has little effect on capital investment or operating costs.

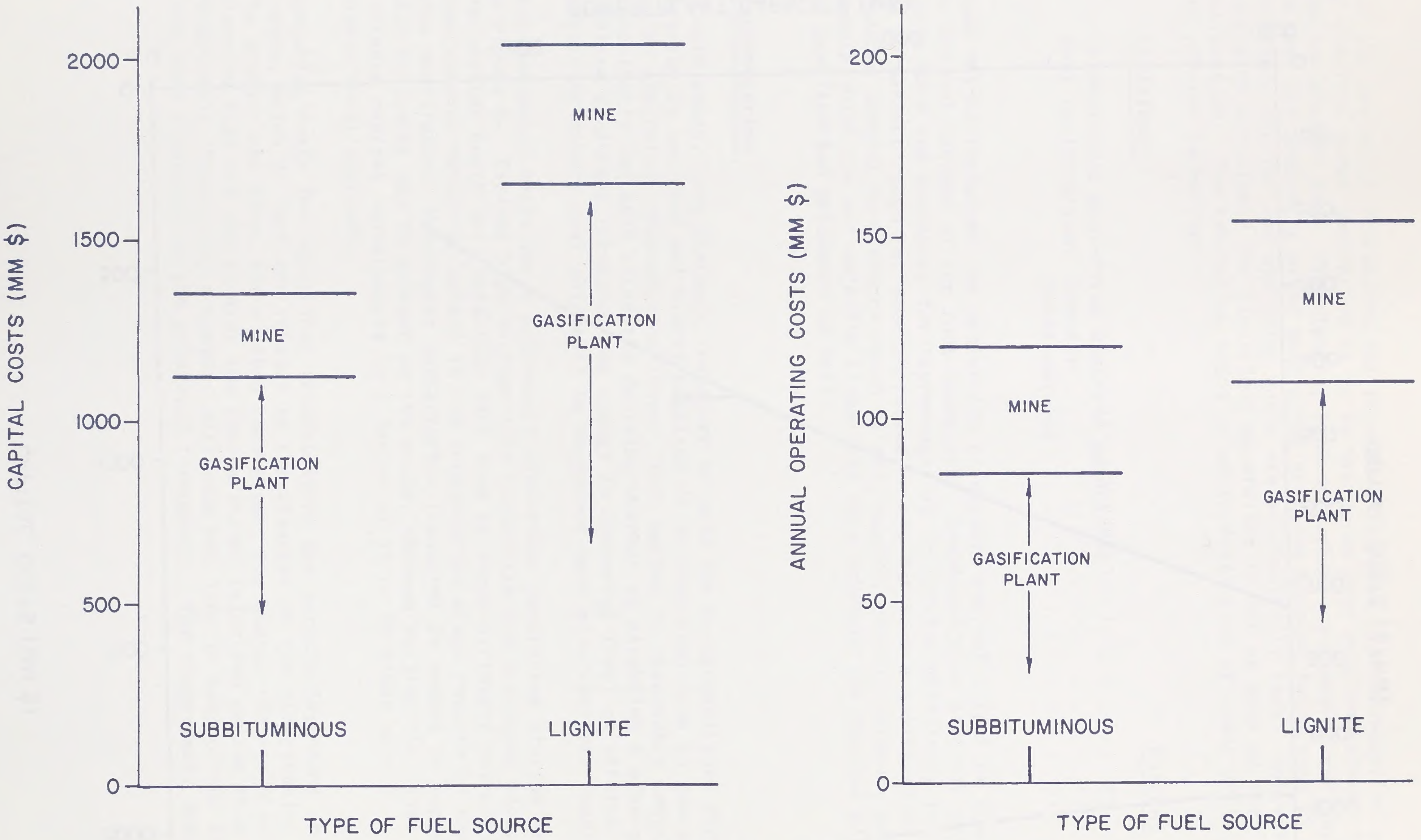


Figure 6. Capital and operating costs for a coal gasification facility (288 mmscfd capacity).

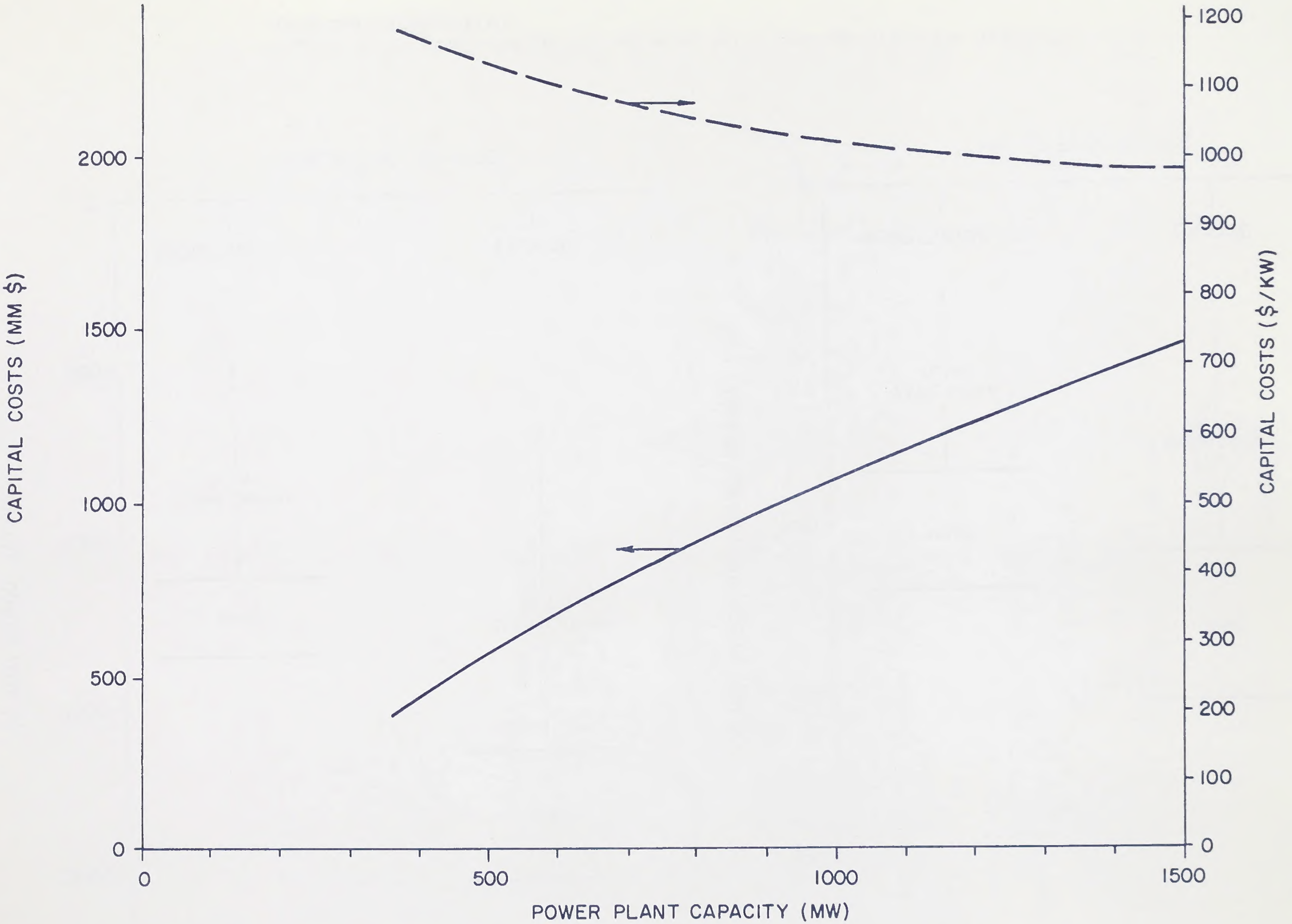


Figure 7. Capital costs for coal-fired generating stations.

From the preceding discussion and figures it appears that consumption of coal for electric power generation is to be preferred over coal conversion to pipeline quality gas. Principally, land disturbance and associated impacts are less for nominally sized generating stations because fewer tons of coal are mined; capital and operating costs are substantially less. However, conversion efficiency for electrical generation is not as good as for gasification. The tabulation below is an approximation of plant efficiencies with current technology:

Efficiency		Percent
Conventional coal-fired electric generation		33
Coal gasification:	Lignite	47
	Subbituminous	52

These values represent the proportion of useable thermal output as compared to the thermal content of the fuel feedstock. Combined-cycle electric power plants have the potential for improvement in conversion efficiency to about the 50 percent range (at some increased cost), but also a gasification plant produces several by-products--such as tar, naptha, phenol, sulphur, and ammonia which are all saleable items--and this enhances the overall efficiency for gasification processes as well.

Transportation

In this study, long distance transport of coal can be accomplished either directly by railroad and slurry pipeline or in converted form in gas pipelines and by electrical transmission lines. Each method is reasonably competitive economically and most often the decision whether to establish a mine-mouth facility (and thus transport the energy in converted form) or offsite facility (requiring direct coal shipment) is dependent upon site-specific conditions.

Transportation costs for a mine-mouth electrical generating station are given in Figure 8. Typical high-voltage line capacities are presented along with the capital costs for installing each line by three different methods. Conventional vehicular access in the construction stage results in the lowest line costs/mile. Helicopter installation (required in remote or rugged areas) will typically add 70 percent to the costs, whereas burying the lines will increase capital requirements by a factor of 15 to 30 times over a conventional approach.

Operating costs for electrical transmissions are largely dependent upon line losses, which in turn are related to the diameter of the distribution wire. The smaller the wire, for a given throughput, the higher the resistance to electron flow and the greater the corona losses (electron escape from the powerline). Typically, a company will size the line to keep corona losses to less than 5 percent of the generated throughput. For comparison, annual

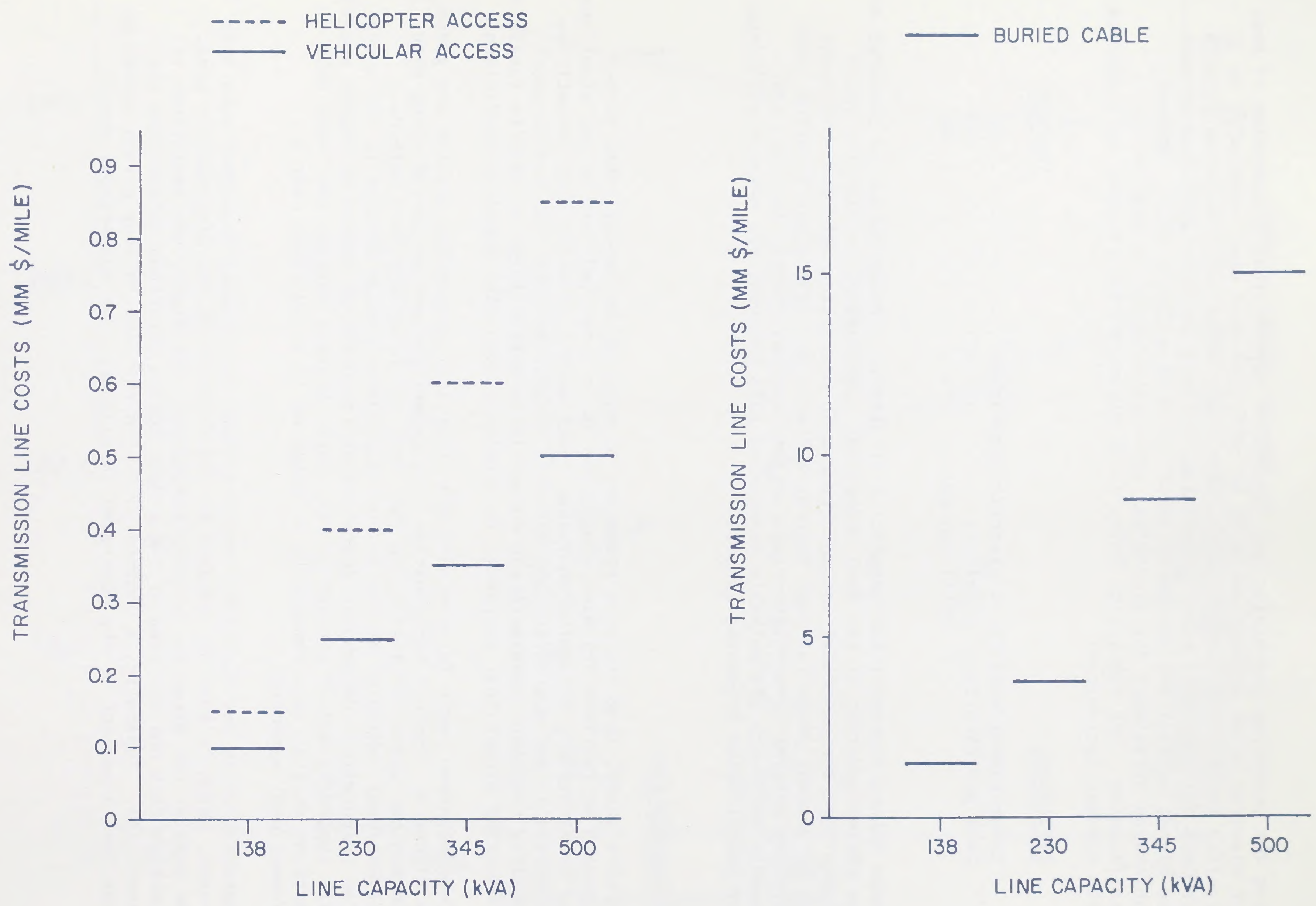


Figure 8. Transmission line costs for various construction methods.

service charges for line maintenance generally fall in the range of 0.2 to 0.5 percent of the capital cost for the powerline, depending upon the severity of the climate; relative to overall transmission losses, this figure becomes rather negligible.

Figure 9 shows both the capital and operating costs which can be expected for gas pipelines. Economies of scale are evident for installation of increasing line capacities, but operating costs remain rather linear. Simple division of respective numbers on the graphs shows that annual operating costs vary from about 3.5 to 5.0 percent of the installed cost.

Operating costs for direct shipment of coal are believed quite comparable to the above estimates. While there is no extensive body of literature covering coal slurry pipelines, a number of studies have been completed identifying the economic advantages and disadvantages of coal slurry shipment versus rail transportation. One of the more exhaustive analyses of long-distance coal shipment suggests that the energy losses for rail transport would approach 3.8 percent of the total thermal value in the coal, whereas comparable movement through a slurry line would consume 3.9 percent of the contained thermal value. Given the uncertainties inherent in such estimates, it is reasonable to conclude that the various modes of energy transportation are basically competitive in an economic sense and that the preferred choice in any situation will be selected based on site specifics.

Sociological

The primary sociological impact of either a power plant or coal gasification facility centers on the personnel requirements during the construction and operational phases.

Figure 10 shows the man-years of effort typically needed to construct power plants over a range of capacities, as well as the manpower requirements for a standard 288-mmscfd coal gasification facility. (Based on energy output, this standard sized gasification complex equates to a 3,350 mW power plant.) An approximate rule of thumb for present-day construction techniques suggests four man-year's effort to build each megawatt of capacity. Thus, a 2,000 mW station will require some 8,000 man-years of construction labor. Labor input for a gasification facility is estimated at 14,000 man-years, a figure quite comparable to an appropriately sized power plant.

From this information, it is a straightforward matter to estimate the sociological economics of constructing one of these kinds of conversion facilities. Assuming direct average payroll costs of, say, $10/hr plus a fringe benefit package of 25 percent, annual payroll charges approach $26,000 per person. Taking the 2,000-mW plant as an example, roughly $208 million will be paid out in the construction phase (essentially 2 or 3 years) for wages and benefits. Construction of a standard sized gasification facility would result in payroll costs, probably over a four-year period, of nearly $364 million.

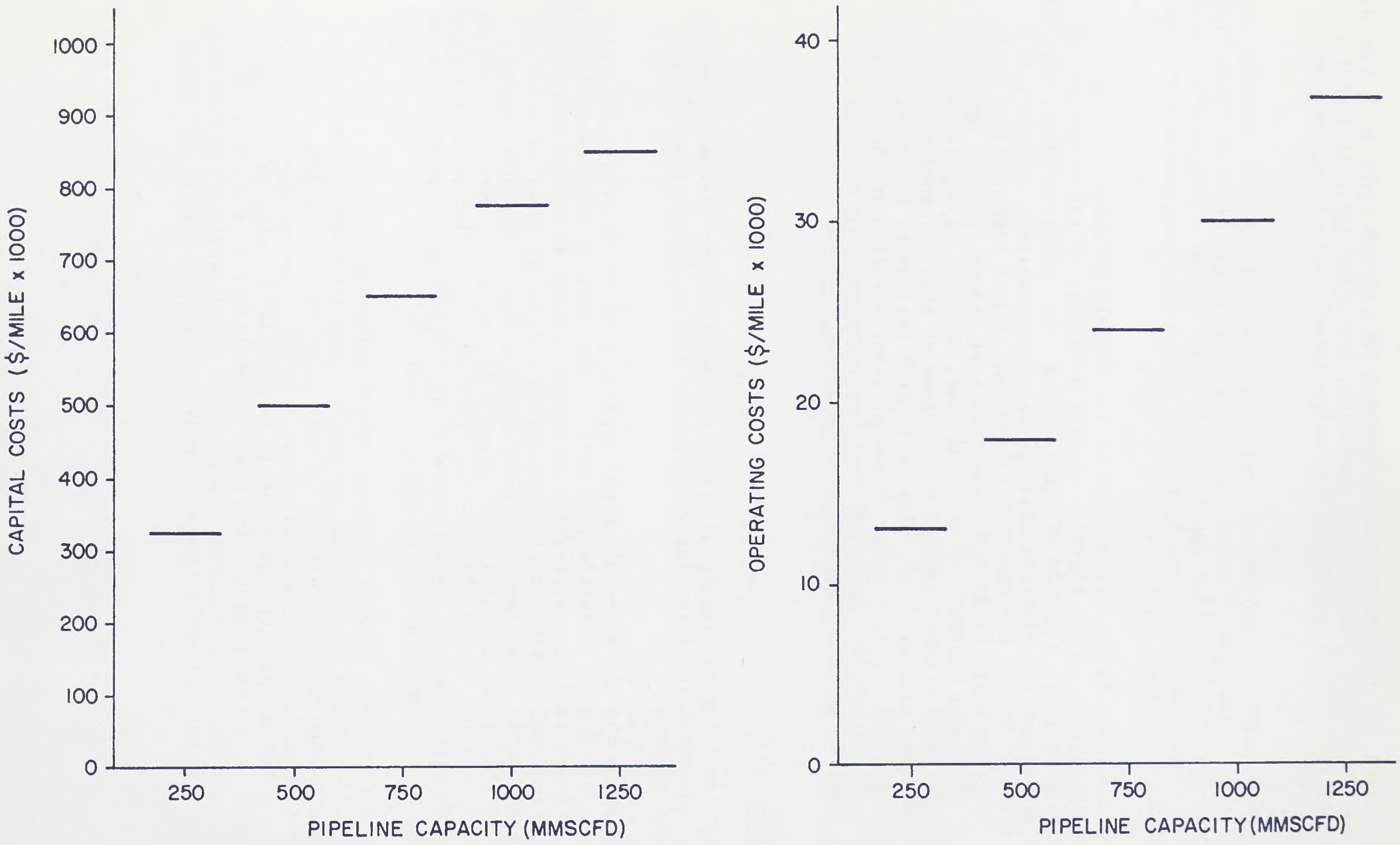


Figure 9. Capital and operating costs for gas pipelines.

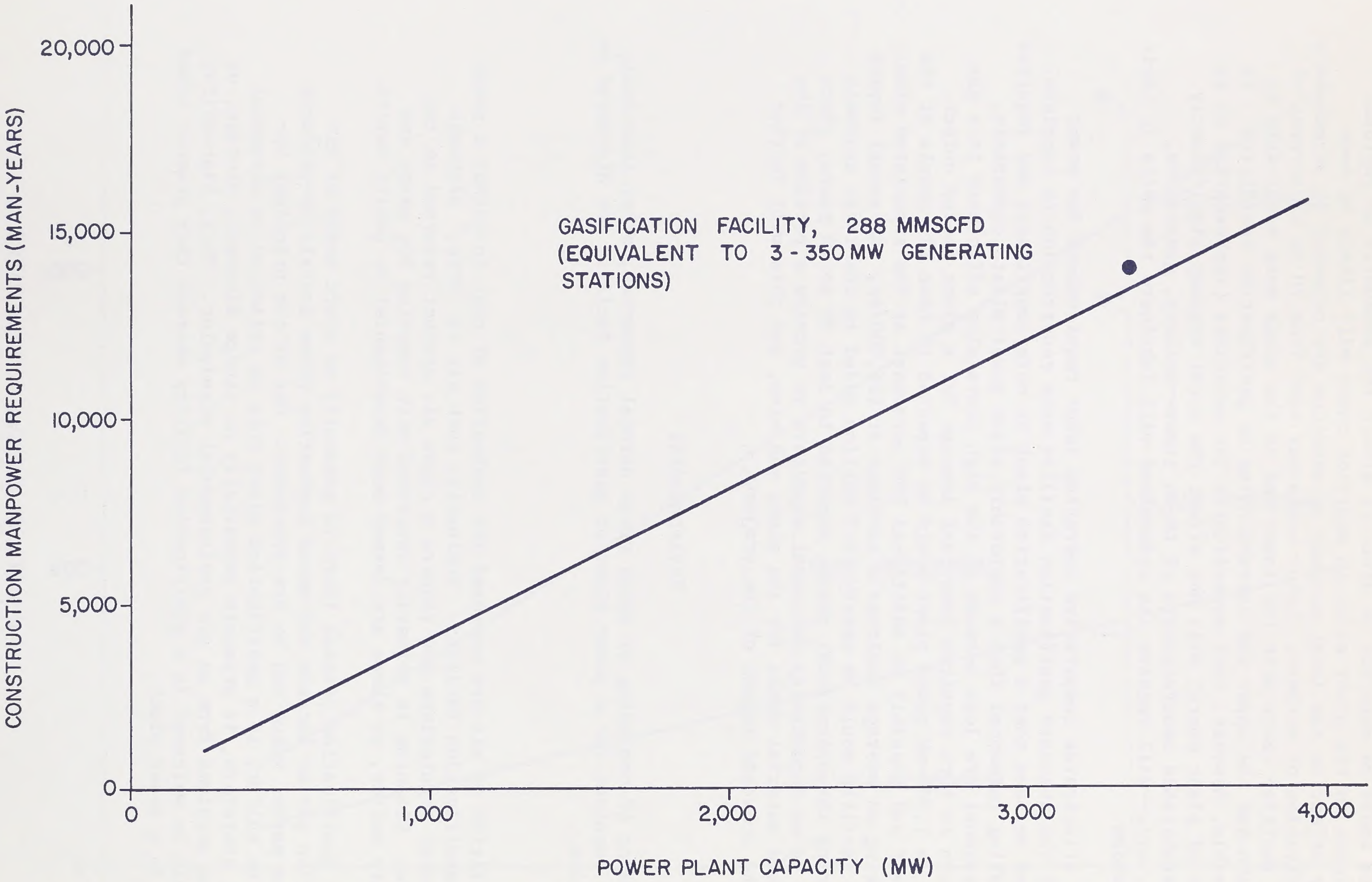


Figure 10. Construction labor requirements, power plants and gasification facility.

These costs could be expected to directly affect the community or regional area proximate to the plant site; in addition there will likely be some multiplier effect on the local economy as services are expanded to accommodate the concentration of workers. Labor costs may vary from 20 to 40 percent of the total facility costs with the lower end of the range more applicable to power plants and the upper end corresponding to gasification facilities. It is conceivable, however, that expenditures for materials (representing 60 to 80 percent of plant costs) will not affect the local economy significantly because established manufacturers of these items--boilers, generators, gasifiers, etc.--will receive the orders and will fabricate the units in their existing shops.

Figure 11 illustrates comparative operating labor requirements for power plants and the standard gasification facility once construction is complete. Here it can be seen that a gasification plant is more complicated and requires more operating personnel than a comparably sized power plant; conversely, mining personnel are less because of the high conversion efficiency in a gas plant, which in turn requires less coal tonnage for a given energy output. Typically, a 1,000-mW power plant could be expected to have 125 people at the plant itself and possibly an additional 200 personnel at the associated mine. Again, taking an average employee's earnings at $26,000/yr, the annual impact of such a facility would be nearly $8.5 million added to the local economic base. During the operational phase, expected to last 30 to 40 years, there will also be an opportunity for local suppliers to provide a portion of the services and material needs for the plant and mine, and this will further enhance the economic impact of the project.

Environmental

The economics of consuming or using those natural resources, other than coal, which are required for a power plant or gasification facility are discussed in this section.

Air

Huge quantities of air are consumed for combustion of coal in either a power plant or gasification facility. Nominally, such air is "free," although environmental regulations now require a clean air product returned to the atmosphere. Cleaning is primarily concerned with removing SO_2 gases and particulate matter, as these are deemed most deterimental to public health.

In a coal gasification process there is generally no overt means of air purification per se because the waste combustion gases contain by-products which have market value and so are processed. One of the principal by-products is sulfur; in a gasification plant this is collected in elemental form and, therefore, it presents essentially no sludge disposal, storage, or rehandling problems from an air environmental standpoint. Thus, high-sulfur coals would be welcomed in a gasification facility whereas they present added problems in a power plant.

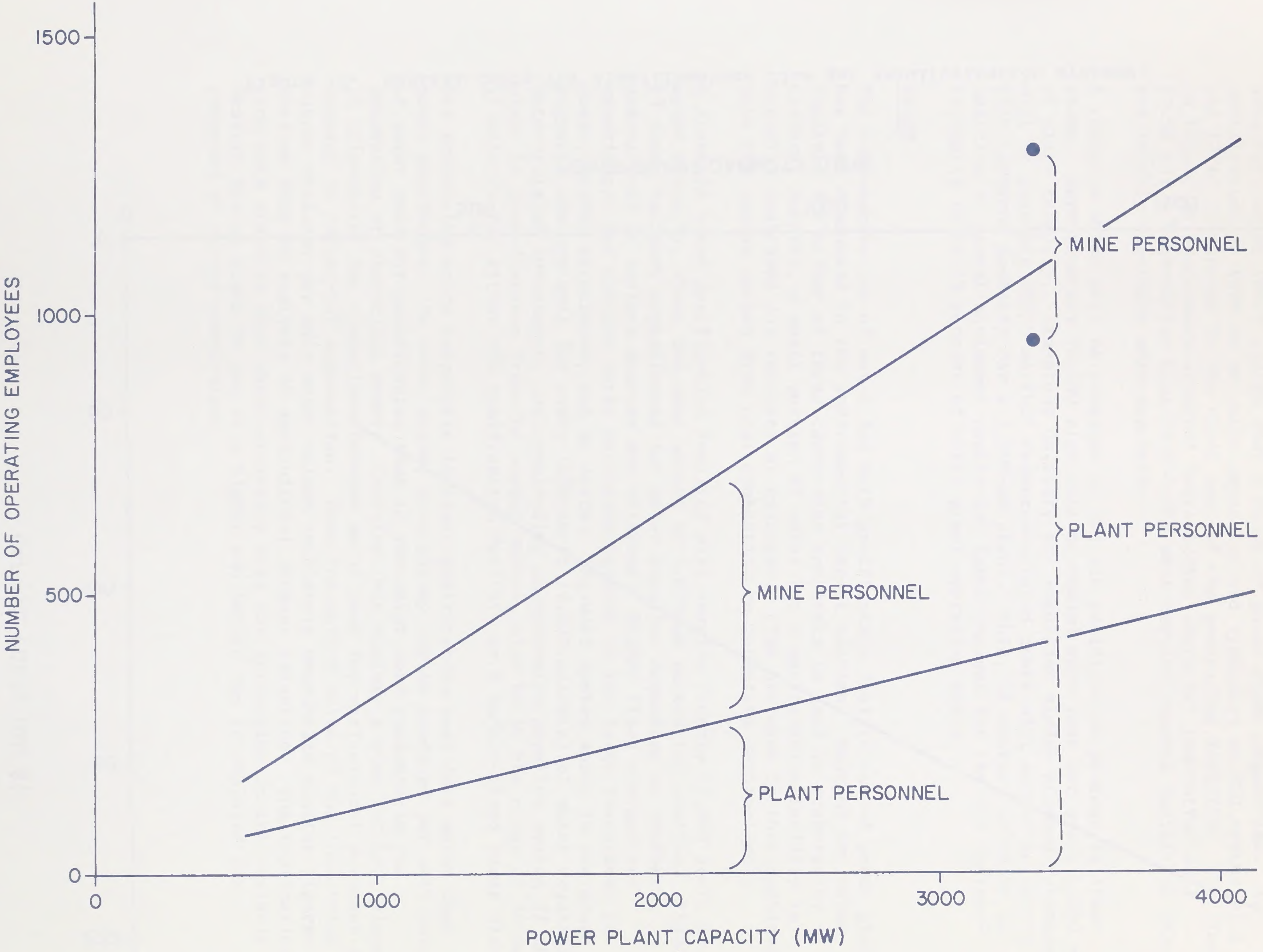


Figure 11. Operating labor requirements, power plants and gasification facility.

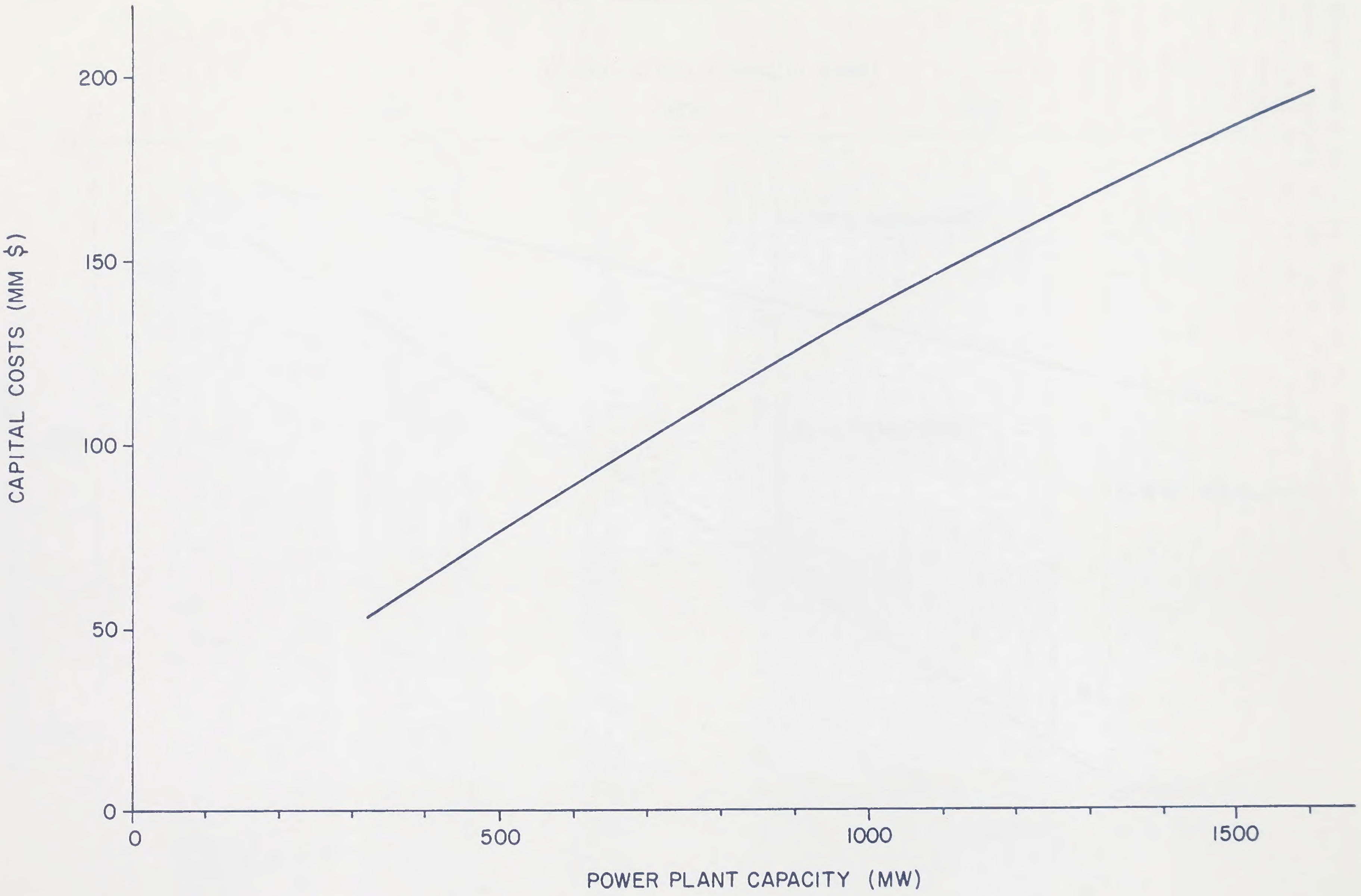


Figure 12. Capital costs for lime/limestone flue gas desulfurization systems.

Figure 12 shows expected capital costs for a lime or limestone flue gas desulfurization (FGD) system over a range of power plant capacities. Air purification is seen to be quite expensive and typically an FGD system will add 12 to 15 percent to the total cost of the generating facility. The line on Figure 10 represents expected installation costs for low-sulfur coal (0.5% ±); a high-sulfur coal (3.0-4.0%) will require removal facilities which are roughly one-third more expensive.

A resource which will be consumed in the air purification process is limestone. Approximately 26,000 t/yr will be needed each year for every 1,000 mW of plant capacity. Limestone delivery and resultant sludge disposal charges will be possibly $20/t so that resource-related costs will amount to nearly $720 thousand annually for a 1,000-mW plant. This, of course, would be in addition to normal equipment repair and labor charges for the FGD system--typically 12 to 15 percent of total plant operating costs.

Water

The consumptive use of water for both gasification facilities and power plants has been discussed in the environmental impact section. Most of the water required for either of these conversion complexes is used in evaporative coolers; however, a small portion of water for a gasification facility is actually destroyed for recovery of hydrogen. (The hydrogen is then combined with the excess carbon from coal combustion to formulate methane gas.)

A standard sized gasification facility will require roughly 11,000 ac-ft of water annually, about the same amount as a 650-mW generating station. Figure 13 shows ballpark expenditures for water supplies depending on whether underground or surface sources are utilized. Higher fixed charges are experienced for surface water purchases because of the large investment in pumps, intake structures, and so forth. The well system shown in the graph suggests one new well for every 1600 ac-ft (1,000 gal/min) of water required. Water-related investment, not considering an extensive pipeline system if the plant is some distance from the supply source, will be in the range of $4 to $7 million for either the gasification facility or a modest-sized power plant.

For conversion units comparable in size, gasification uses less water than power generation. In other words, more energy can be produced per unit volume of water used for gasification than if the water were consumed in the generation of electrical power. Carrying this analogy a step further, Figure 14 illustrates the comparison between water used for agricultural purposes as opposed to industrial application. Here the market value of the industrial output produced per unit water volume completely overwhelms similar figures derived from an analysis of agricultural product valuation. The implication from this graph is that water presently used for irrigation in the semiarid Western States might be put to a higher and better use if employed for purposes of energy conversion.

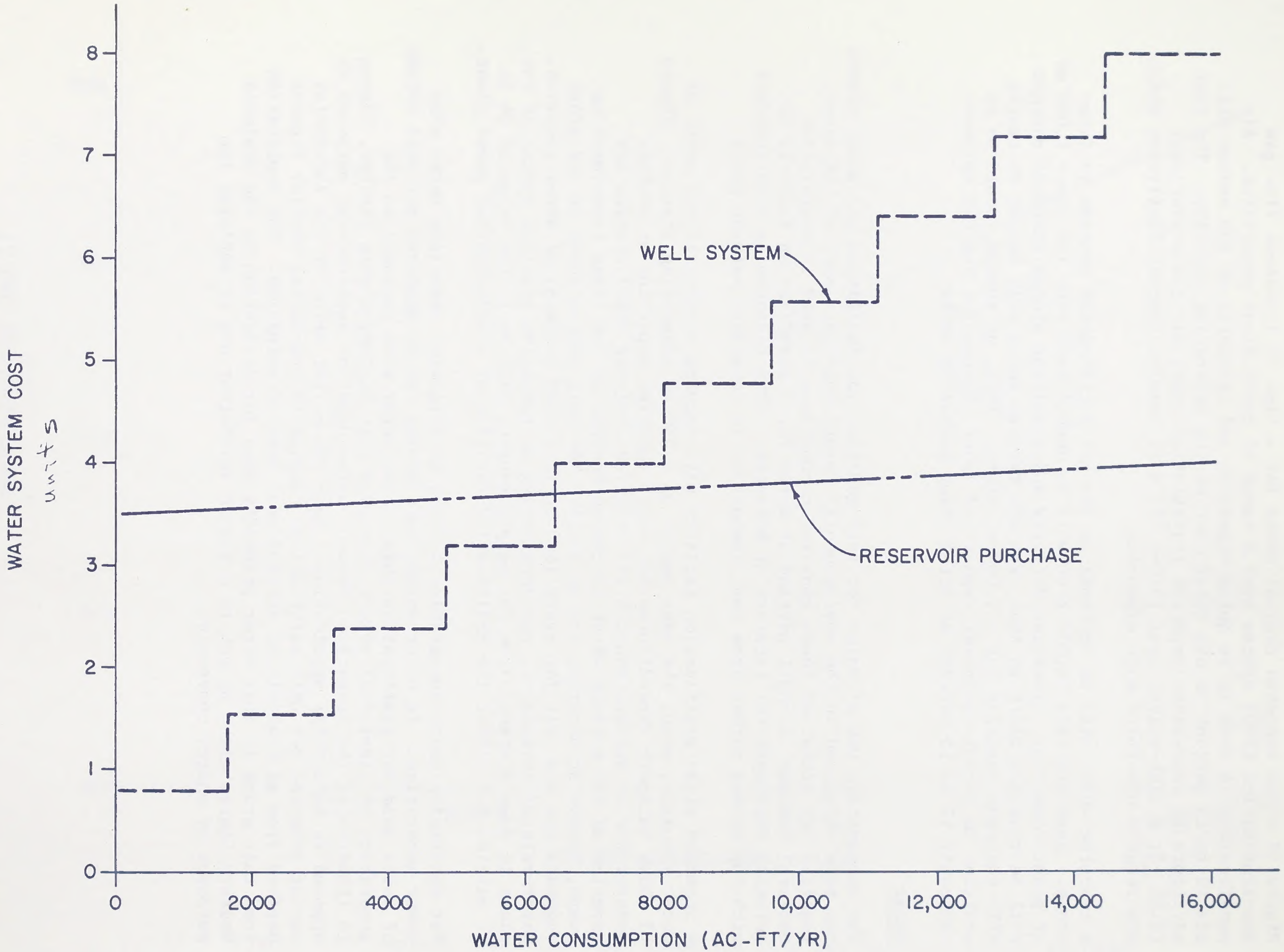


Figure 13. Water system costs.

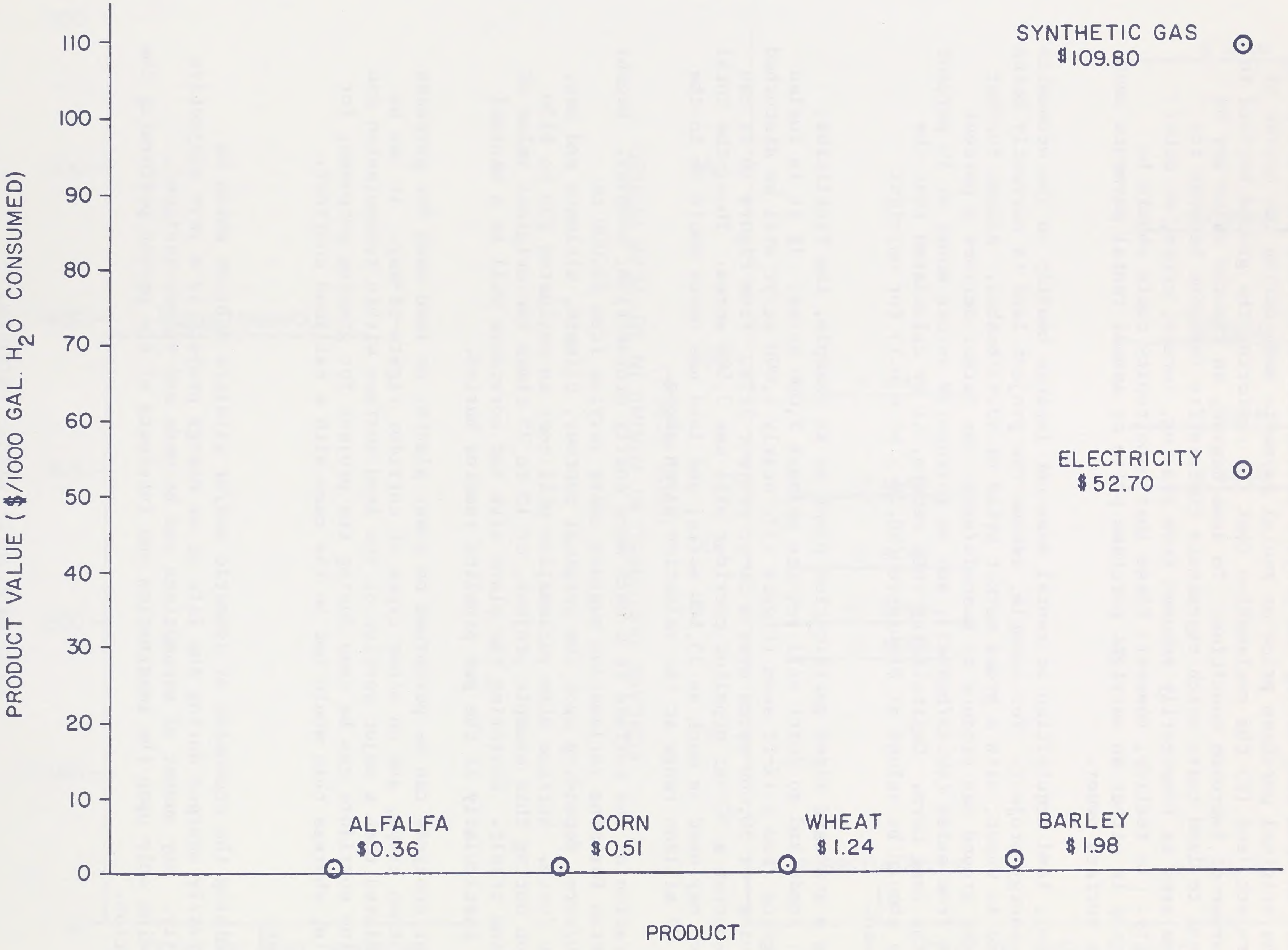


Figure 14. Comparative values of water usage.

Land

The cost of land used during the project period can be divided into two parts: (1) the original purchase price or rental payments made during the course of the project, and (2) the reclamation cost for restoring the ground surface to its former or improved condition. To some degree, an imputed value may be assigned to land costs which represents the profits foregone because the surface area is temporarily removed from grazing, forest, crops, or other activity. In reality, however, these lost opportunity costs should be reflected in either an outright purchase price or annual rental payments made to the surface owner.

In total, land acquisition or rental does not impinge heavily on the economics of an energy project. For example, assume the project land is currently being planted in wheat, with a gross market price of $3.65/bushel. Assume further that the ground can produce 65 bushels/acre, the farmer derives 8 percent profit from sales ($0.29/bushel), and he personally values money at 10 percent over the long term. Capitalizing this return, it is calculated that the ground should be valued at $188/acre ($0.29 x 65 ÷ 0.1) for outright purchase.

Taking a standard sized gasification plant as an example, the facilities, ponds, roads and so forth will require perhaps 2,000 acres. If it is fueled by lignite from a 12-ft seam (Figure 15), nearly 1,000 ac/yr will be disturbed by mining--or 30,000 acres over a 30-yr project life. From Figure 16 it can be seen that a 300-mi pipeline corridor will use 3,500 acres. Thus, the total project may need as much as 35,500 acres, and land use costs would be in the $6 to $7 million range at the valuation given above.

Restoration of the surface is a much more costly proposition, however. Recent estimates for mine reclamation suggest costs varying from $3,000 to $5,000/acre, depending upon the original contour, climate, ultimate end use, and so forth. Surface mine reclamation will cost an estimated $90 to $150 million during this example project, or 15 to 25 times the original value of the land itself. Restoring the plant site and corridors will be a minimal cost, particularly if the gas pipeline remains buried.

Similar analyses can be performed on power plants, on land used for purposes other than crops, and on other types of corridor rights-of-way. It can be appreciated that a major portion of the land surface within transmission and pipeline corridors can be used during the project for grazing purposes, for example, whereas this would not be the case with a railroad corridor.

Habitat

Determining the economics of domestic and/or wildlife habitat which is temporarily usurped during the life of an energy project is a very subjective activity. Any number of assumptions can be made and values assigned, depending only upon the imagination and interests of the person performing the valuation.

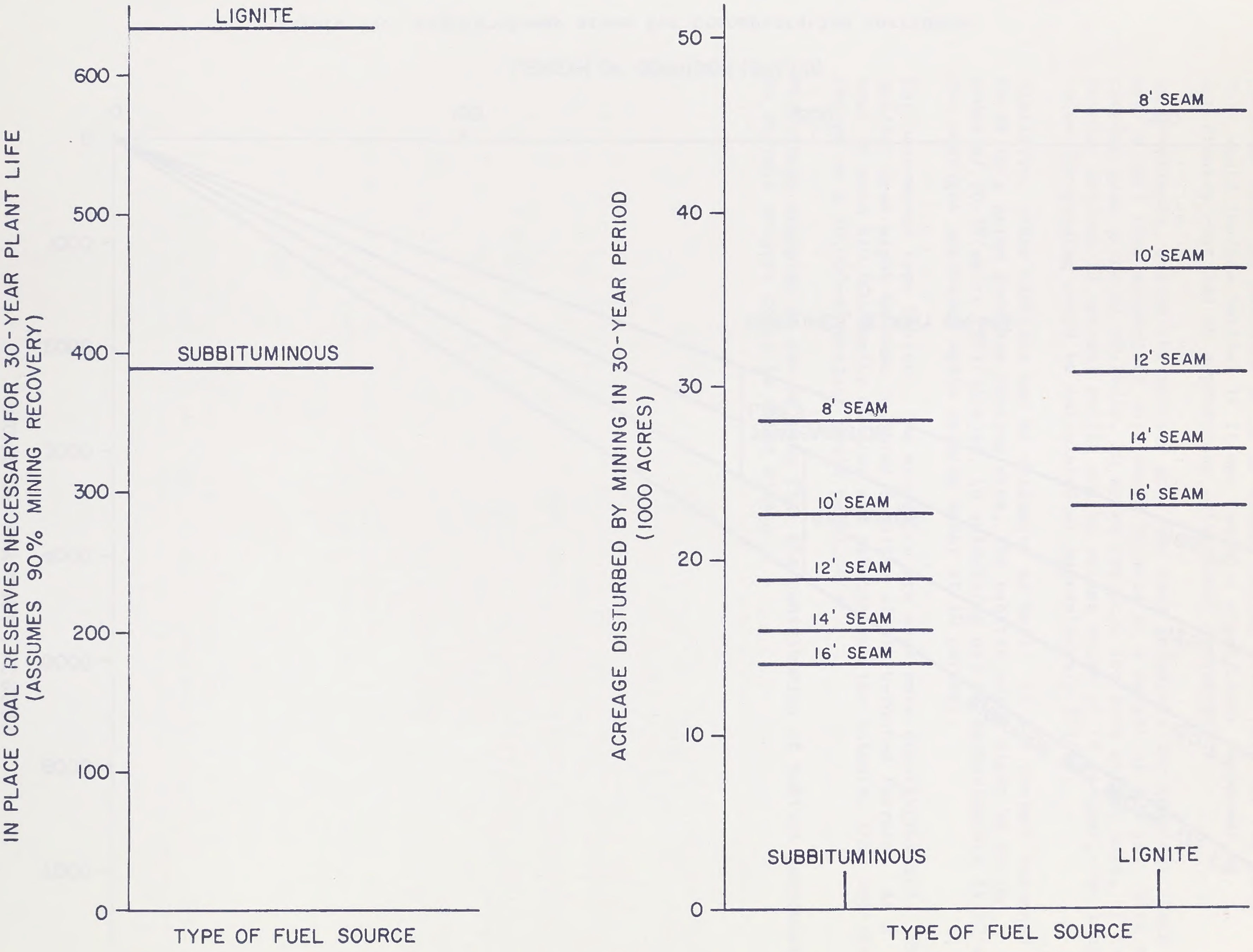


Figure 15. Required coal reserves and disturbed area by coal rank.

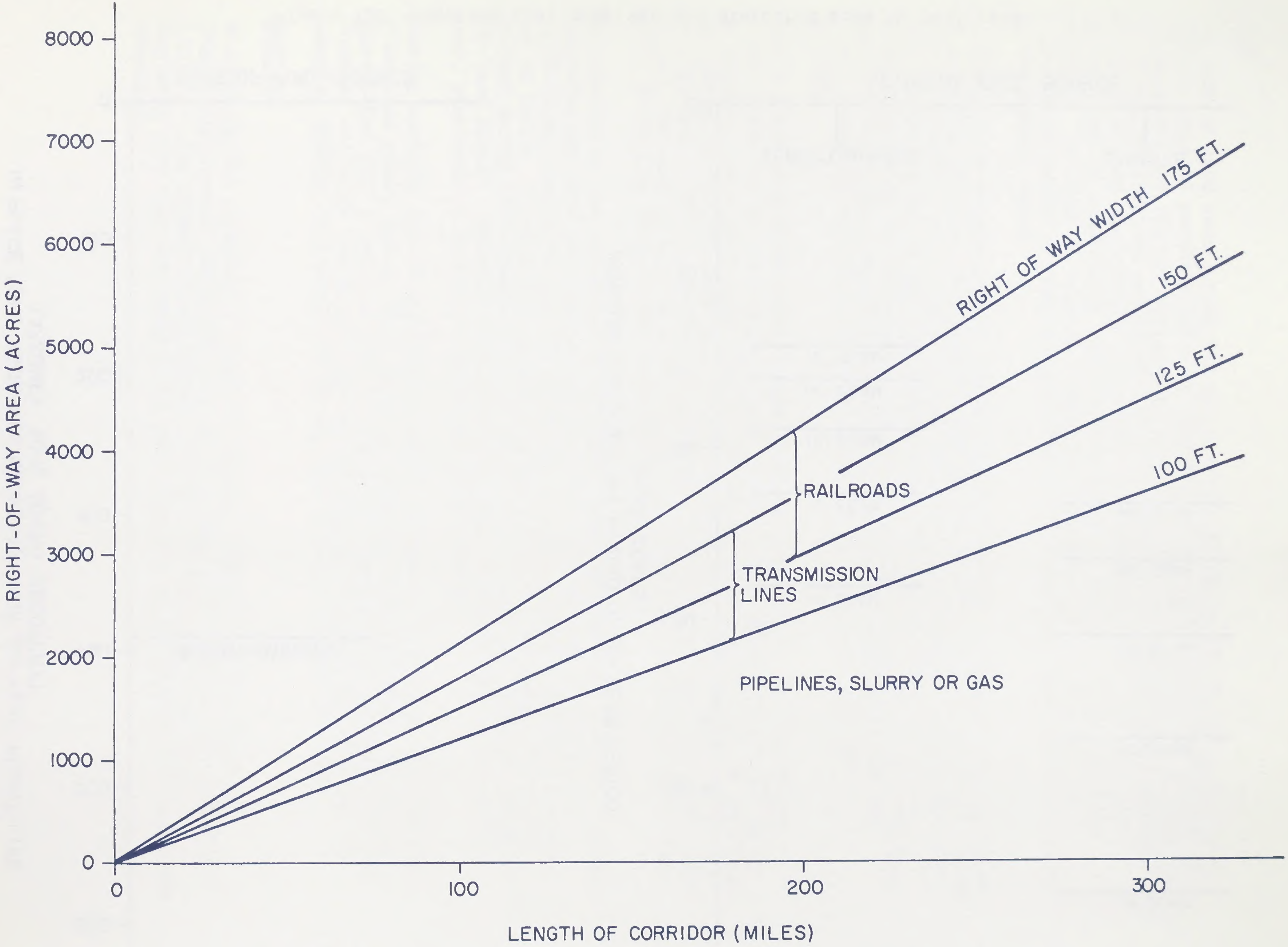


Figure 16. Rights-of-way areas for transportation corridors.

As indicated in the discussion of land values, any opportunity loss should be factored into the purchase price or annual rental price paid for the land. This would include habitat if it was deemed a significant component of opportunity cost and an appropriate value could be assigned.

As an example, assume the project area was used primarily for grazing. Each year a calf from a cow-calf unit would be sold at a weight of 600 lb. With a current sale price of \$0.70/lb, 20 acres required for each animal unit, if the rancher derives 15 percent profit and he values money at 10 percent, the land value for grazing could be calculated at approximately \$31/ac.

Similarly, other habitats can be evaluated as well. If the project happened to be in a prime antelope hunting area, the habitat value might be on the order of \$0.39/ac/yr (\$25/license, 10 animals/sq mi) or approximately \$4.00/ac for outright purchase, again valuing money at 10 percent.

For nonrevenue type habitat, the economics are even more straightforward. The project area might be home to three families of black-footed ferrets. At a cost of even \$10,000/family to trap and reestablish the animals, this one-time charge to a 30,000-ac project would be \$1.00/ac.

From these examples it can be seen that the contribution of habitat economics to overall project costs is quite minor.

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ENGINEERING ASPECTS OF SURFACE COAL MINE PLANNING, DEVELOPMENT, AND OPERATION

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PLANNING PROCEDURE

Planning a surface mine requires consideration of many variables with complex interrelationships (Table 1). Following collection of general deposit and project-related information, a development and extraction plan is conceived. Project economics are determined and an economic analysis is performed to determine project viability. Note that Steps III and IV are iterated until an "optimum" solution is found. These iterations may include consideration of various mining method/equipment combinations, mine size/equipment combinations, mining method/pit layout combinations, etc.

As seen in reviewing the list of variables and information, the problem areas relate to geology, engineering, environmental sciences, and economics. As a result, the planning and development process is interdisciplinary in nature and requires inputs and guidance from numerous individuals with diverse backgrounds and training. The correct mine plan will result in a feasible operating plan as well as one which optimizes the economic return subject to the numerous contractual, environmental, legal and other constraints related to the specific property.

Jones (1977) has outlined the 10 major steps involved in planning and developing a surface coal mine. These steps are detailed in Table 2 and shown in a Gantt chart in Figure 1. The planning and development process can take up to 10 years and require millions of dollars of expenditure exclusive of that for actual mine preparation and equipment purchase.

RESERVE ESTIMATION

A major portion of the planning process centers on the reserve estimate and geologic "model" of the deposit. These estimates can be quite preliminary or can be made in great detail. The level of effort will correspond to the stage in the exploration/development program.

Sampling Methods

In most cases, a combination of rotary and diamond core drilling methods are used to obtain sample data from the deposit. Rotary drilling is used to determine overburden depth and coal thickness. A rotary rig is used to drill through the coal seam(s). A geophysical probe is then lowered into the hole and a log of the hole is produced. Combinations of parameters such as gamma logs and density logs are used to pick the coal/overburden interface. Quality data (e.g., btu/lb, % ash, % S, etc.) are obtained by diamond core drilling. The solid cores of the coal seam are processed in a lab with the analysis returned for appropriate posting. Core data of the overburden are taken occasionally to determine if toxic overburden exists on the property.

TABLE 1

SALIENT FACTORS REQUIRING CONSIDERATION IN MINE PLANNING AND FEASIBILITY STUDIES

I. INFORMATION ON DEPOSIT

A. Geology

Overburden

- stratigraphy
- geologic structure
- physical properties (highwall & spoil characteristics, degree of consolidation)
- thickness and variability
- overall depth
- topsoil parameters

Coal

- quality (rank and analysis)
- thickness and variability
- variability of chemical characteristics
- structure (particularly at contacts)
- physical characteristics

B. Hydrology (Overburden and Coal)

- permeability
- porosity
- transmissivity
- extent of aquifer(s)

C. Geometry

- size
- shape
- attitude
- continuity

D. Geography

- location (proximity to distribution centers)
- topography
- altitude
- climate
- surface conditions (vegetation, stream diversion)
- drainage patterns
- political boundaries

TABLE 1 (CONT.)

E. Exploration

- historical (area, property)
- current program
- sampling (types, procedures)

II. GENERAL PROJECT INFORMATION

A. Market

- customers
- product specifications (tonnage, quality)
- locations
- contract agreements
- spot sale considerations
- preparation requirements

B. Transportation

- property access
- coal transportation (methods, distance, cost)

C. Utilities

- availability
- location
- right-of-way
- costs

D. Land and Mineral Rights

- ownership (surface, mineral, acquisition)
- acreage requirements (on and off-site)
- location of oil and gas wells, cemeteries, etc.

E. Water

- potable and preparation
- sources
- quantity
- quality
- costs

F. Labor

- availability and type (skilled & unskilled)
- rates and trends
- degree of organization
- labor history

G. Governmental Considerations

- taxation (local, state, Federal)
- royalties
- reclamation & operating requirements
- zoning
- proposed and pending mining legislation

III. DEVELOPMENT AND EXTRACTION

A. Compilation of Geologic and Geographic Data

- surface and coal contours
- isopach development (thickness of coal and overburden, stripping ratio, quality, and costs)

B. Mine Size Determination

- market constraints
- optimum economics

C. Reserves

- method(s) of determination
- economic stripping ratio
- mining and barrier losses
- burned, oxidized areas

D. Mining Method Selection

- topography
- refer to previous geologic/geographic factors
- production requirements
- environmental considerations

E. Pit Layout

- extent of available area
- pit dimensions and geometry
- pit orientation
- haulage, power & drainage systems

F. Equipment Selection

- sizing, production estimates
- capital and operating cost estimates
- repeated for each unit operation

TABLE 1 (CONT.)

G. Project Cost Estimation (Capital & Operating)

- mine
- mine support equipment
- office, shop and other facilities
- auxiliary facilities
- manpower requirements

H. Development Schedule

- additional exploration
- engineering and feasibility study
- permitting
- environmental approval
- equipment purchase and delivery
- site preparation and construction
- start-up
- production

IV. ECONOMIC ANALYSIS

- sections III and IV repeated for various alternatives

TABLE 2

MAJOR STEPS IN SURFACE MINE DEVELOPMENT

I. Assembly of the Mineable Coal Package

- Lease acquisition
- Mapping the area
- Drilling program development
- Surface drilling rights acquisition
- Drilling, sampling, logging, analysis
- Mineral evaluation (determination of commercial quantities present)
- Drilling on closer centers (development drilling)
- Sampling, logging, analysis
- Surface acquisition

II. Market Development

- Market survey
- Potential customer identification
- Letter of intent to develop and supply
- Contract negotiation

III. Environmental and Related Studies

- Initial reconnaissance
- Scope of work development
- Consultant selection
- Implementation
- Environmental impact report
- Environmental monitoring

IV. Preliminary Design, Machine Ordering

- Conceptual mining development
- Economic size determination
- Mining system design, layout and development
- Equipment selection
- Stripping machine ordering
- Mine plan development

V. NEPA Process (National Environmental Policy Act of 1969)

- Identification of lead agency for Environmental Impact Statement (EIS)
- Draft EIS
- EIS review and comments
- EIS hearing and record
- Federal EIS review
- Council on Environmental Quality filing
- Mining, and/or reclamation plan approval

TABLE 2 (CONT.)

VI. Permits

- State water well and rights appropriation permits
- State special use permit - such as a reservoir
- State mining permit
- State industrial siting permit
- Federal NPDES permit
- Federal Forest Service special land use permit

VII. Design and Construction

- Preliminary design and estimation
- Material ordering and contracting
- Water well development
- Access roads and site preparation
- Railroad construction
- Power supply installation
- Facilities and coal handling construction
- Warehouse building and yards
- Coal preparation and loading facilities construction
- Overland conveyor construction

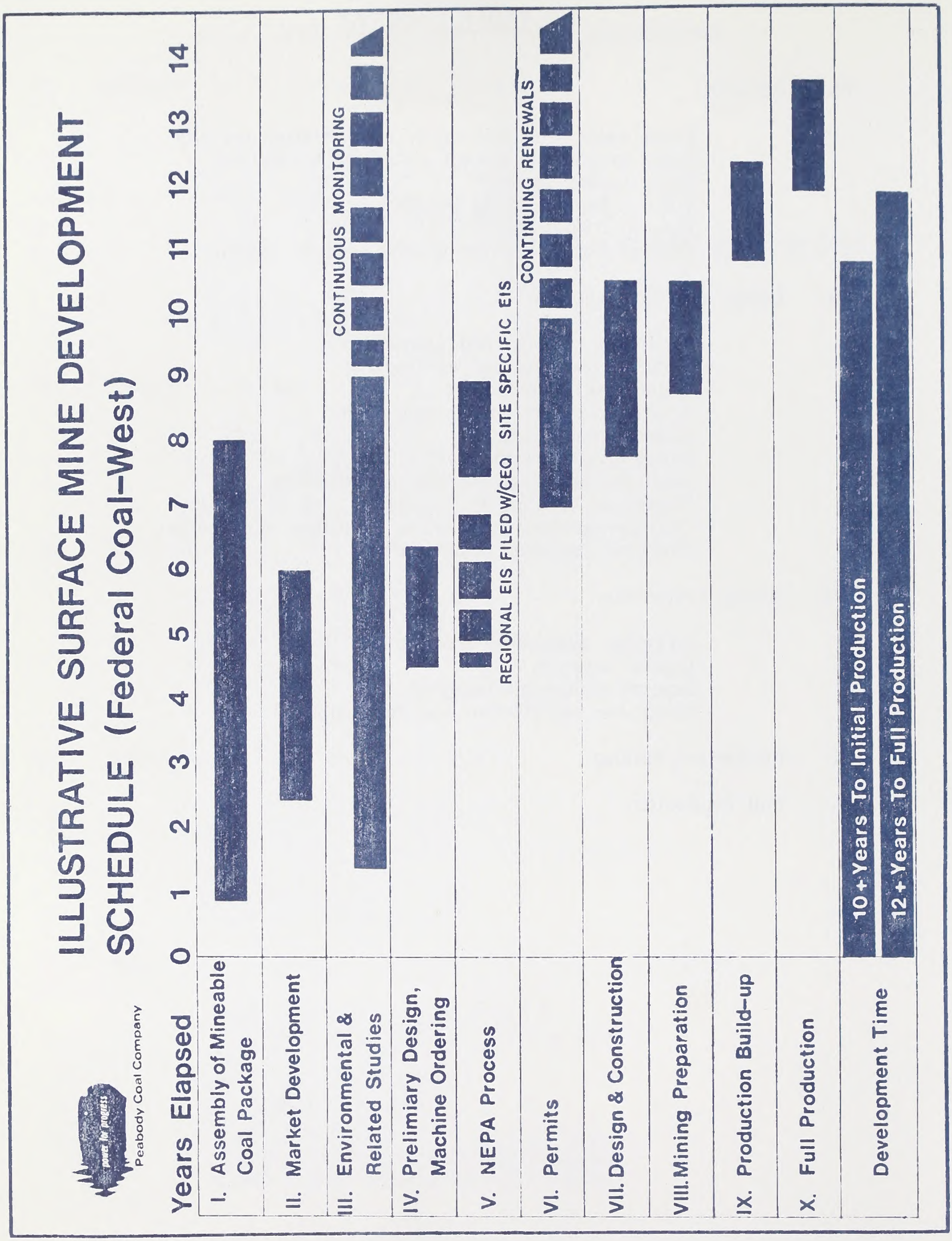
VIII. Mining Preparation

- Stripping machine(s) erection
- Loader erection
- Support equipment readying
- Manpower recruitment and training

IX. Production Buildup

X. Full Production

Figure 1.



(Jones 1977)

Sample spacing will vary depending on the variability of thickness and quality parameters of the seam. An initial rotary grid spacing (e.g., 2,000 ft.) might be followed by a closer-spaced grid (e.g., 1,000 ft.) or a hole at the center of the original grid. This follow-up drilling is usually done to provide further resolution in a second phase of drilling which would be contingent upon success in the more widely spaced initial program. The coal core drilling is usually done on a lesser spacing than rotary drilling. Closely spaced fences of holes are normally drilled perpendicular to the cropline to determine the extent of the burned or oxidized zone. This contact usually corresponds to some depth of overburden. However, in areas where the overburden is badly fractured, the burned or oxidized zone may not correlate with depth of overburden and more extensive drilling will be required. Overburden coring is usually performed with a hole density of approximately four to five holes per section.

Calculation Methods

The method of calculation used will be a function of the seam variability and to some extent the mining history of the seam in the particular locale.

Tons/acre

The tons per acre approach is commonly employed where there is little seam variability or where a rapid approximation of reserves, overburden, and stripping ratio is required. As seen in Table 3, the method involves calculating the tons of coal/acre-ft and then multiplying this figure by average thickness of the coal to determine the tons/acre of coal. The area of reserves in acres is then multiplied by the tons/acre of coal to arrive at the reserve. Two reserve figures are generally presented: (1) the in-place reserve, and (2) the recoverable reserve, which includes allowances for mining and for preparation plant recoveries.

Similarly, overburden/acre is calculated using the average overburden height and the reserve area is multiplied by this figure to arrive at total overburden.

The average stripping ratio (i.e., bank cubic yards of overburden per ton of coal) is calculated by dividing total overburden by total coal, usually on a recoverable basis. In these approximate calculations, average coal and overburden thickness dimensions are usually based on a simple mean of the drill hole data. The area is usually found by planimetering the area bounded by the outcrop, subcrop, and/or property lines. If more precision is required, techniques such as the polygon or triangular approach can be used to more precisely assign areas of influence to the drill holes. However, the iso-line approach is most commonly used when a detailed reserve and overburden analysis is required.

TABLE 3

RESERVE CALCULATIONS - TONS/ACRE METHOD

1. $\frac{\text{Tons}}{\text{Ac-Ft}} = 43{,}560 \; \frac{\text{Ft}^2}{\text{Ac}} \; \text{X} \; \frac{\text{Coal Density}}{2000\#}$

   E.g., Density = $82\#/\text{Ft}^3$

   $\frac{\text{Tons}}{\text{Ac-Ft}} = 43{,}560 \; \text{X} \; \frac{82}{2000} = 1{,}786 \; \frac{\text{Tons}}{\text{Ac-Ft}}$

2. $\frac{\text{Tons}}{\text{Ac}}$ (Raw) = $\frac{\text{Tons}}{\text{Ac-Ft}}$ X Average Thickness (Ft)

   E.g., Average Thickness = 4.5 Ft

   $\frac{\text{Tons}}{\text{Ac}}$ (Raw) = 1,786 X 4.5 = 8,037 $\frac{\text{Tons}}{\text{Ac}}$ (Raw)

3. $\frac{\text{Tons}}{\text{Ac}}$ (Recoverable) = $\frac{\text{Tons}}{\text{Ac}}$ (Raw) X Mining Recovery X Preparation Plant Recovery

   E.g., Mining Recovery = 90% Prep. Plant Recovery = 85%

   $\frac{\text{Tons}}{\text{Ac}}$ (Recoverable) = 8,037 X .90 X .85 = 6,148 $\frac{\text{Tons}}{\text{Ac}}$ (Rec.)

4. Tons (Raw) = $\frac{\text{Tons}}{\text{Ac}}$ (Raw) X Ac

   E.g., 640 Ac

   Tons (Raw) = 8,037 X 640 = 5,143,700 Tons

5. Tons (Recoverable) = $\frac{\text{Tons}}{\text{Ac}}$ (Recoverable) X Ac

   E.g., 640 Ac

   Tons (Recoverable) = 6,148 X 640 = 3,934,700 Tons

Stripping Ratio

6. $\frac{\text{Overburden}}{\text{Ac}} = 43{,}560 \; \frac{\text{Ft}^2}{\text{Ac}} \; \text{X} \; \frac{\text{Avg. Overburden}}{27 \text{ Cu Ft/Cu Yd}}$ (Ft)

   E.g., Overburden Thickness = 60 Ft

   $\frac{\text{Overburden}}{\text{Ac}} = 43{,}560 \; \text{X} \; \frac{60}{27} = 96{,}800 \; \frac{\text{Cu Yd}}{\text{Ac}}$

7. Stripping Ratio or Overburden Ratio

   Stripping Ratio = $\frac{\text{Overburden/Ac}}{\text{Tons/Ac (Recoverable)}}$

   E.g., Tons/Ac = 6,148

   Stripping Ratio = 96,800/6,148 = 15.7 $\frac{\text{Cu Yd}}{\text{Ton}}$

Iso-line

The iso-line method involves construction of lines of equal values for overburden thickness and coal thickness in an effort to present a model of these parameters representing the deposit.

The iso-overburden map is generated by using the surface topography map and a topographic map of the top of the coal seam. The latter is constructed by using drill hole data (depth to top of coal) and the surface drill hole collar elevations. The two maps are then overlaid and by subtraction of the surface and top of coal elevations, the thickness of overburden can be established either at the topography intersections or on a regular grid basis. These values are then contoured to produce the iso-overburden thickness lines.

The iso-coal thickness map is generated either by using the top and bottom coal contours or by interpolation of actual drill hole thickness intercepts. When coal structure contours are used, the top and bottom coal elevation maps are overlaid and the values calculated at either the line intersections or at regular grids. These thicknesses are contoured to produce the iso-coal thickness lines. If coal intercepts are used directly, the values are interpolated to produce the thickness iso-lines. The most common approach is utilization of the coal structure topography because these maps are utilized in pit haulage and drainage planning.

The coal thickness and overburden thickness iso-lines are then utilized to calculate the amount of overburden and coal using procedures outlined in Table 4. The data are usually summarized by overburden range as is indicated in Step 8, Table 4.

Iso-stripping ratio lines can also be constructed by overlaying the overburden and coal thickness map, calculating the stripping ratio at the line intersection or on a regular grid, and then interpolating and contouring the stripping ratios. The iso-stripping ratio map is extremely useful in determining the economic limits, as discussed in a subsequent section.

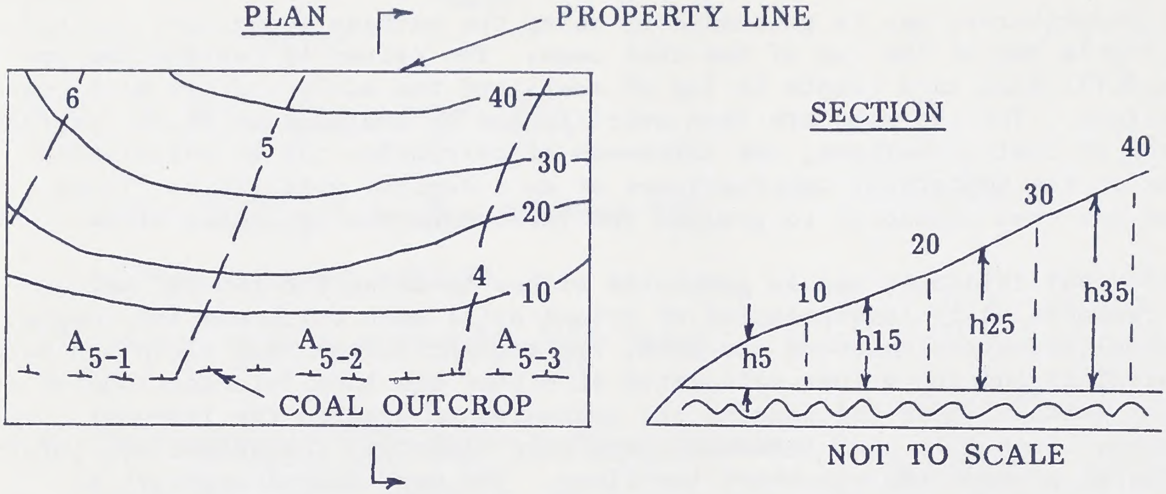
Computer Models

Many operators utilize computer software to perform the previously described reserve calculations and to generate the associated graphics utilizing flatbed plotters. A typical software system will have the following capabilities:

- Drill hole data loading and editing with data including drill hole identification, location, lithology on a from-to basis, rock type, seam codes, coal seam analysis, etc.
- Drill hole data listing and abstracts.

TABLE 4

RESERVE CALCULATIONS - ISO-LINE METHOD



——xx—— Overburden iso-lines or contours

----xx---- Coal iso-lines or contours

1. Construct iso-overburden lines.
2. Measure areas bounded by iso-overburden lines with planimeter. (E.g., A_5(outcrop-10), A_{15}(10-20), etc.)
3. Assign thickness to overburden, calculate volume for each "slice."

Area	Height	Yardage (Axh/27)
A_5	h_5	CY_5
$\vdots$	$\vdots$	$\vdots$
A_n	h_n	CY_n
		Sum CY

4. Construct iso-coal thickness lines.
5. Measure sub-areas bounded by iso-overburden & iso-coal thickness lines for each A_n or "slice."
6. Assign coal thickness to each sub-area and calculate coal quanity. Summarize, calculate stripping ratios, etc.

TABLE 4 (CONT.)

Sub-area	Coal Thickness	Tonnage $A_{5-i} x T_{5-i} x$ Density/2000	Stripping Ratio CY_n/T_n
A_{5-1}	T_{5-1}	Ton_{5-1}	
.	.	.	
.	.	.	
.	.	.	
A_{5-m}	T_{5-m}	Ton_{5-m}	
		T_5	SR_5

7. Repeat 5 and 6 as required.

8. Data usually summarized as follows:

Overburden Range	Overburden Quantity	Coal Quantity	Stripping Ratio
0-10			
10-20			
20-30			
30-40			
40+			

- Drill hole data quality summaries by seam, list, and area with averages for specified parameters.
- Polygonal reserves with reserves by hole and seam with maps generated showing polygonal shapes.
- Topography loading by drill hole or by digitizing contour maps.
- Vertical cross-sections to scale showing overburden, coal, and other input data.
- Plan maps showing drill hole locations, crop lines, property lines, etc.
- Interpolation of data to produce gridded model of overburden thickness, coal thickness, top and bottom coal elevations, etc.
- Seam reserves based on gridded data for any area or series of areas with ability to limit reserves based on numerous parameters or combinations of parameters (e.g., minimum coal thickness, maximum overburden thickness, maximum percent sulfur, etc.)
- Mining cut data generated on a cut-by-cut basis to allow simulation of alternative mine plans and comparison of coal and overburden amounts, coal quality, etc.

Such software is available from numerous companies. A fairly complete catalogue of programs available was compiled by Cline (1981). Use of computer-assisted reserve calculation and mine planning must be considered the state-of-the-art in the surface coal mining industry.

Limitations

In arriving at a mineable reserve for a specific property, consideration must be given to various limitations and losses which will be encountered. These can be grouped into economic limits, equipment limits, and mining and barrier losses. All of these factors will result in coal left in place or lost in the process of extraction. The mineable reserve is usually significantly less than the in-place or geologic reserve.

Economic Stripping Ratio

The economics of stripping increasing amounts of overburden is a factor controllable by mine management. The basic premise involves setting a minimum acceptable profit/ton of coal recovered and then adjusting the amount of stripping to satisfy that profit constraint. Such an approach results in a maximum allowable stripping ratio and places a boundary on the area that can be mined economically.

The concept in illustrated in Table 5. As seen in the example, the portion of the property with a limit greater than 32 cu yd/ton would not be considered a surface mineable reserve and thus the reserve would exclude that area.

It should be noted that costs of production exclusive of stripping and stripping costs should be "marginal" costs and not average costs. The marginal costs should represent the best estimate of actual costs at that specific area on the property. For example, consideration must be given to any additional costs of stripping caused by greater depths of overburden or any additional haulage costs resulting from increased haulage distances.

Equipment Limitations

In some cases stripping equipment digging-depth limitations or coal loading equipment height limitations may limit the mineable area.

In some deposits, highwall or spoil instability may preclude use of deep-digging techniques and limit the mineable area with a maximum digging depth. In this situation, extended bench or spoil side pullback may not be possible, causing a depth limit on the reserve (deep-digging methods will be described in a later section).

A minimum coal thickness is required to economically recover thin seams using surface techniques. In very thin seams, dilution from top and bottom material will preclude recovery of a marketable product. As a result, depending on the coal loading technique employed, areas with coal thicknesses below that minimum would be considered unmineable.

Mining and Barrier Losses

Mining losses are those associated with the extraction process. These losses include the following:

- Top of coal: losses at upper coal contact with overburden as a result of cleaning coal after stripping.
- Bottom of coal: losses at lower coal contact with bottom as a result of loader losses; both top and bottom losses as a percentage are a function of seam thickness.
- Rib: losses at side of seam adjacent to spoil as a result of spoil piled on coal rib during stripping or slides of spoil on coal; function of pit width.
- Other: includes fly rock (blasting) and transportation losses (dust and spillage).

TABLE 5

ECONOMIC OR ULTIMATE STRIPPING RATIO CALCULATIONS

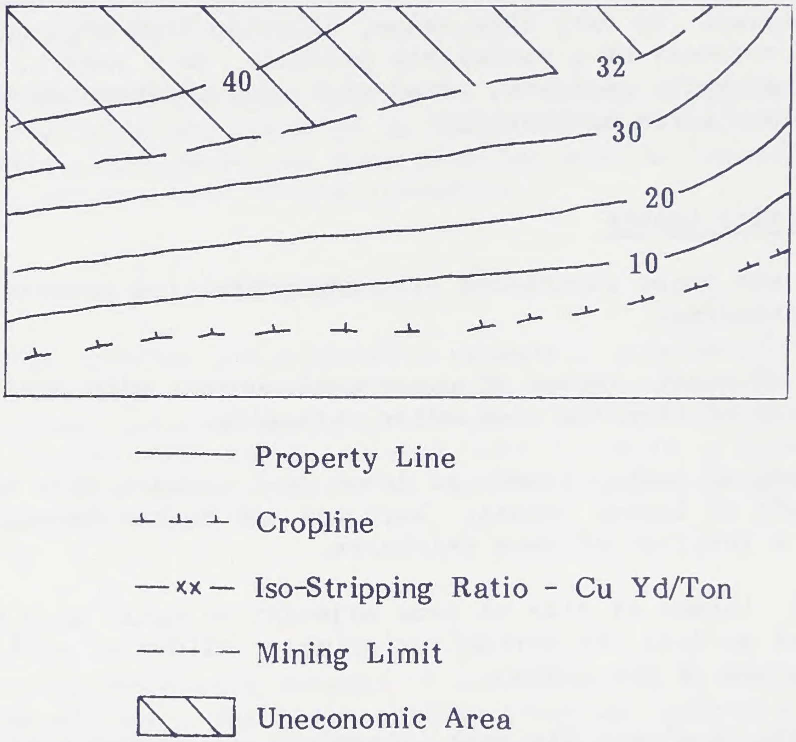
$$\text{Economic Stripping Ratio} = \frac{\text{Recoverable Value/Ton} - \text{Production Cost/Ton}^{*} - \text{Minimum Profit/Ton}}{\text{Stripping Cost/Cu Yd}}$$

*Exclusive of Stripping

E.g.,
Recoverable Value = $17.00/Ton
Minimum Profit = $ 3.00/Ton
Stripping Cost = $ .25/Cu Yd
Production Cost* = $ 6.00/Ton

$$\text{Economic Stripping Ratio} = \frac{17.00-6.00-3.00}{.25} = 32\ \frac{\text{Cu Yd}}{\text{Ton}}$$

Plan



In eastern area operations, these losses account for 10.7% of the reserve (IC 8738). In thicker-seam western operations, these losses would probably be a lesser percentage because of the thicker seams and wider pits generally encountered.

Barrier losses are caused by coal left in place for various practical and regulatory reasons. The barrier losses include outcrop (coal left as a low-wall barrier or for quality reasons), right-of-way, stream, underground mine, oil and gas wells, property line, building, and cemetery. In eastern area operations, these losses account for 5.2% of the reserve (IC 8738). These losses are quite site-specific and depend on the geologic and geographic setting of a property.

Mining and barrier losses are significant and are given thorough consideration in estimating the mineable reserves.

MINING METHODS AND EQUIPMENT

The mining method selected for a specific property is generally keyed to the overburden removal system, since this unit operation usually involves the greatest capital and operating cost components. Once the stripping method and complementary equipment have been selected, compatible equipment systems are selected for the other unit operations (i.e., coal fragmentation, coal loading and hauling, etc.).

The following sections describe the major method/equipment systems commonly encountered in large western mining operations. In addition, major performance standards (OSM regulations) are integrated into the presentation of unit operations.

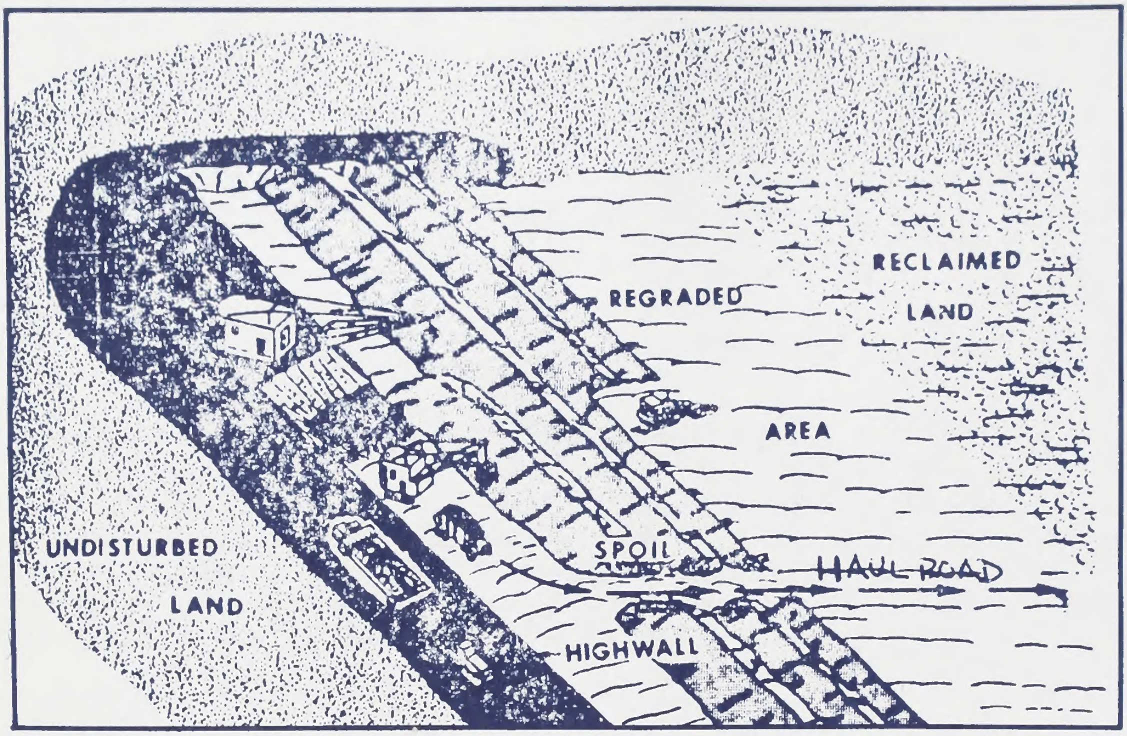
As previously mentioned, standard engineering practice dictates that various alternatives be investigated for not only the stripping system but also for the other unit operations. The goal is to provide maximum resource extraction at a minimum cost including capital and operating cost considerations.

Area/Dragline

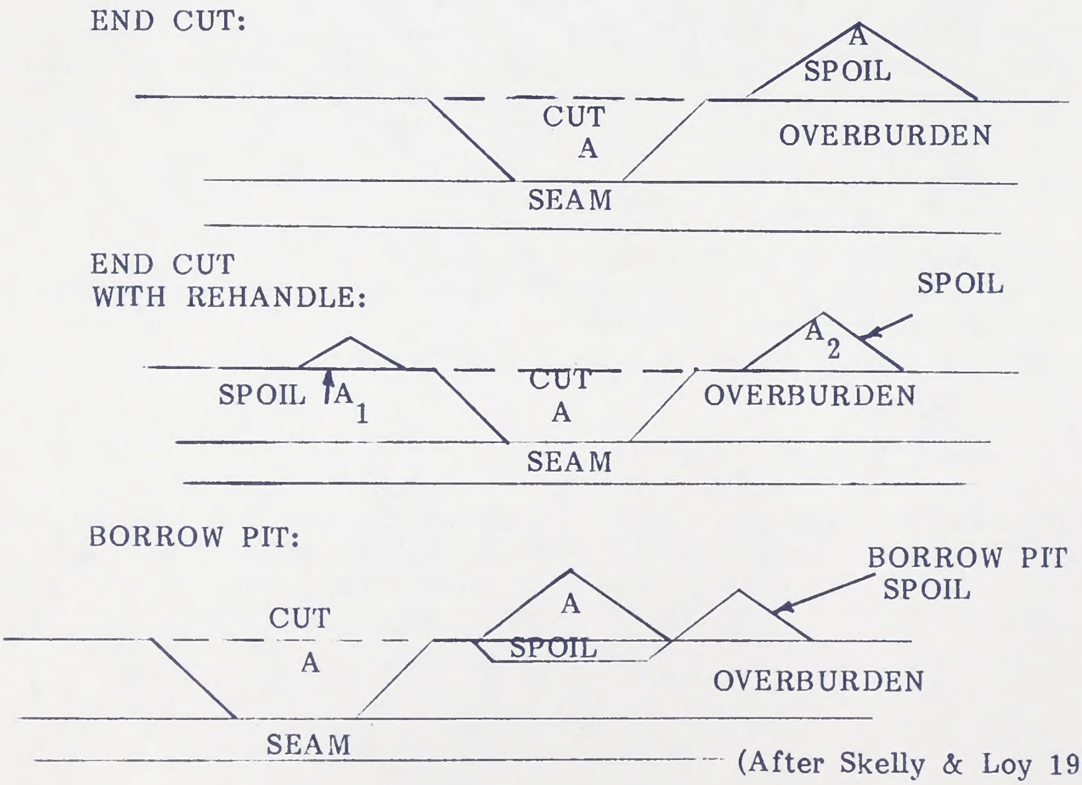
The area/dragline method (Fig. 2) involves opening an initial box cut, removing the coal exposed in the box cut, and then placing the overburden from the next longitudinal cut into the mined out box-cut area. The procedure is then repeated on a cut-by-cut basis. The method is also referred to as "deep plowing."

The method is generally employed in flat to moderately dipping coal seams with relatively constant overburden depths. Such a method can also be employed in areas where coal dip or overburden slope result in reaching the economic limit in relatively few cuts. In this mode, the method is referred to as a modified area or box-cut contour operation. The major difference is the rate at which the limit is reached.

Figure 2. Area/Dragline Operation



BOX CUT METHODS



(After Skelly & Loy 1975)

Advantages and Disadvantages

The advantages and disadvantages of the area/dragline method combine the characteristics of the dragline and this method. Generally speaking, the alternative piece of equipment used to perform the stripping is the stripping shovel. The industry has not purchased a large stripping shovel since 1971 and there are only approximately 20 stripping shovels (i.e., eight crawler, direct casting machines) currently in operation. Draglines have been chosen in these applications primarily because of their flexibility in varying operating conditions. The dragline can handle varying overburden depths, varying overburden characteristics, and multiple seams by changing the operating mode. Although these changes often cause some loss in machine productivity, they allow mining through the specific set of conditions without major additions of auxiliary equipment which would be required with a stripping shovel. For example, see Atkinson (1971) and Steidle (1977) for a discussion of stripper selection.

The major advantages and disadvantages of an area/dragline system are indicated below.

Advantages

- Low direct operating cost/cubic yard of overburden.
- High machine availability as a percent of scheduled time.
- Long useful life (20 years plus).
- Flexible and versatile under various field conditions; high overburden, multiple seams, various overburden conditions, deep box cuts.
- Can strip a wide range of overburden material with appropriate overburden preparation.
- Works on highwall, eliminating pit congestions, coal crushing by stripper, and resultant coal losses.
- Stratigraphic control possible, but with resultant loss in productivity.
- High labor productivity; not labor-intensive.

Disadvantages

- High capital cost with progress payments required.
- Long lead time to final erection and operation--minimum of 18 months on large machines.
- Limited horizontal transport capability due to operating radius; ability to restore to original contour limited without rehandling.
- Support equipment required for moving benching strike-off, and topsoil removal.
- Pit production depends on single machine.
- Limited coal blending ability from pits because of fixed plan; blending accomplished by stockpiling or using multiple pits but limited by walking speeds and road preparation.

- Materials with low highwall and spoil angles require excessive machine reach, which may preclude use of the dragline.
- Stratigraphic control possible, but with loss of productivity.

Unit Operations

In the following sections each unit operation is discussed in terms of procedures, typical equipment, and relative performance standards.

Clearing and grubbing: This involves clearing the property of trees and shrubs and then removing the stumps and roots to insure a homogeneous topsoil. Grubbing is often done with rake-like grubbing attachments on agricultural tractors or dozers.

Topsoil removal: Regulations dictate that topsoil be removed and ultimately replaced upon the graded spoils. The topsoil can either be stockpiled at the side of the pit area for later redistribution or hauled immediately to the graded area for redistribution. In the latter case, the topsoil can either be hauled around the pit or across the pit on spoil bridges. The decision is made on the basis of economics considering topsoil quantities and haul distances.

Self-elevating scrapers are the most common means of removing and redistributing topsoil, although loader/truck or wheel excavator/belt systems find application where topsoil quantities are large and/or haul distances are long.

Topsoil thicknesses are usually determined by auger drilling, and the regulations dictate that a minimum of 6 inches of material be removed. In cases where multiple soil horizons (i.e., A, B and C) exist, these layers must be removed separately and stockpiled and redistributed to maintain the integrity of each horizon. Topsoil storage, if longer term, must be revegetated to prevent water and wind erosion.

Overburden preparation: Following topsoil removal, overburden is usually drilled and blasted to fragment the material to allow efficient excavation. Drilling is performed with electric-powered rotary blasthole rigs drilling holes in the 7 to 15 in. diameter range. Patterns range from 20 x 20 ft to 40 x 54 ft depending on hole diameter and degree of overburden consolidation. The holes are usually loaded with bulk ANFO (approximately 94% ammonium nitrate prill and 6% fuel oil mixture by weight) with cast primers and water gels as primers. Water gels are also used in wet holes or where hard toe conditions exist. Powder factors of .3 to .4 lb/bank cubic yard are common. The regulations relating to blasting are fairly significant and include the following:

- Scheduling: Sunrise to sunset with public notice required 10 to 20 days prior to blast.

- Blasting surveys: Preblast surveys of dwellings in the mine vicinity are required to alleviate questions relating to blasting damage.

- Residential limits: No blasting can be conducted within 1,000 ft of a dwelling unless a pre-blast survey is completed and seismic monitoring is performed.

- Peak particle velocity: Regulations are designed to maintain peak particle velocity less than 1 in/sec and have been the source of legal challenge by the industry.

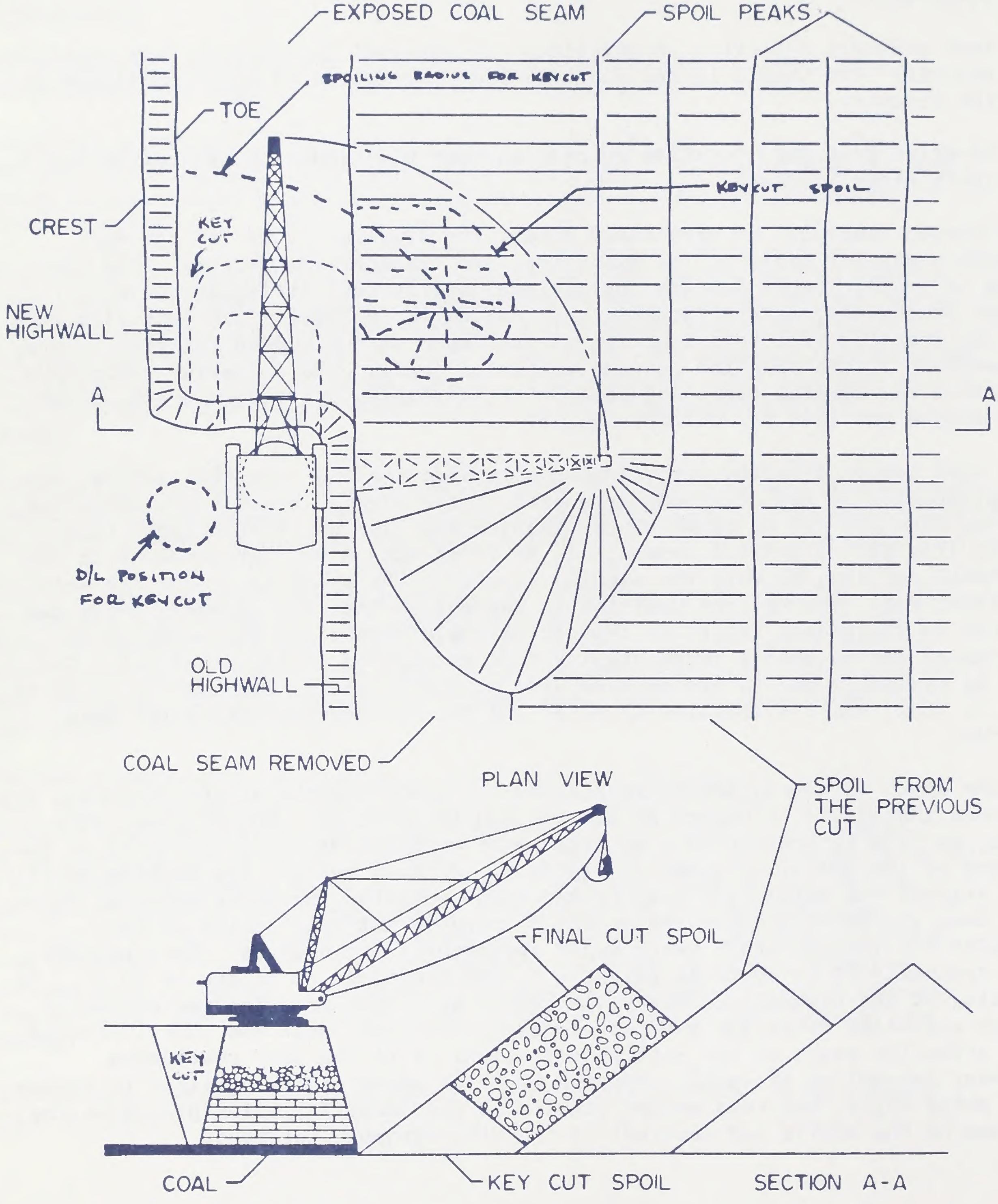
- Detailed records: Detailed records on each blast must be maintained for 3 years after a blast.

Overburden removal: As previously noted, the dragline is by far the most common excavator employed for excavating and transporting material from the bank to spoil. Other systems include excavator/truck, stripping shovels, wheel excavators, scraper/dozers, and combination systems. The operating mode of the dragline will be a function of the depth of overburden relative to the dimensions of the dragline and the number of seams. The following paragraphs describe the typical operating modes with increasing overburden depth, first for single and then for multiple seams.

The most common dragline operating mode is side casting. In this method, the dragline sits on top of a bench prepared on the blasted overburden. Material is dug from the cut in front of the machine and cast up to 90 degrees into spoil (Fig.3). A typical approach is to first make a key cut parallel to the highwall and then to walk the machine closer to the spoil to remove the main or final cut. The key cut position is assumed so that the highwall angle can be cut to the proper angle, so that swing angle on the key cut material is minimized and so that a third digging face is exposed on the final cut. The key is typically one to two buckets wide at top of coal. Each set-up is 50 to 100 ft long, and the dragline is moved and the process repeated after each set-up.

As the depth of overburden increases and the reach ability of the dragline becomes inadequate, a number of methods can be utilized. One of them, chop down, is done by excavating a working bench with the dragline operating at the bottom of the bench, as shown in Figure 4. In this method, the machine moves the regular cut using side casting and then excavates the bench material above its base elevation placing the bench or chopdown material on top of the regular cut spoils with a swing angle approaching 180 degrees. Such benches are typically 30 to 40 ft in height and have been done to depths of 70 ft. In looking at the highwall geometry, it can be seen that lowering the operating bench elevation moves the machine closer to the spoil peak and thus increases the effective reach of the machine and allows it to dig deep overburden without rehandling of spoil. Advance bench chopdown can be utilized to reduce the swing angle, but this method results in shop material being placed on the bottom of the spoils and reversal of the stratigraphic horizons.

Figure 3. Dragline Side Casting



Note: Dragline position, last spoiling radius, and keycut spoil location shown dotted in plan.

(After Bucyrus-Erie 1976)

In addition to allowing the dragline to dig deeper, chopdown can be utilized to establish the working bench elevation and to provide stratigraphic control. In rolling topography, chopdown can be used to cut the high areas and thus establish a consistent operating bench elevation as required by the machine. Chopdown, as shown in Figure 4, will provide stratigraphic control by placing the top overburden back on top in the spoils. It should be noted that due to the higher swing angle and poor digging efficiency resulting from digging above grade, production losses result when the method is employed. Losses range from 25 to 75% when compared to side casting (Bucyrus-Eris Co. 1976).

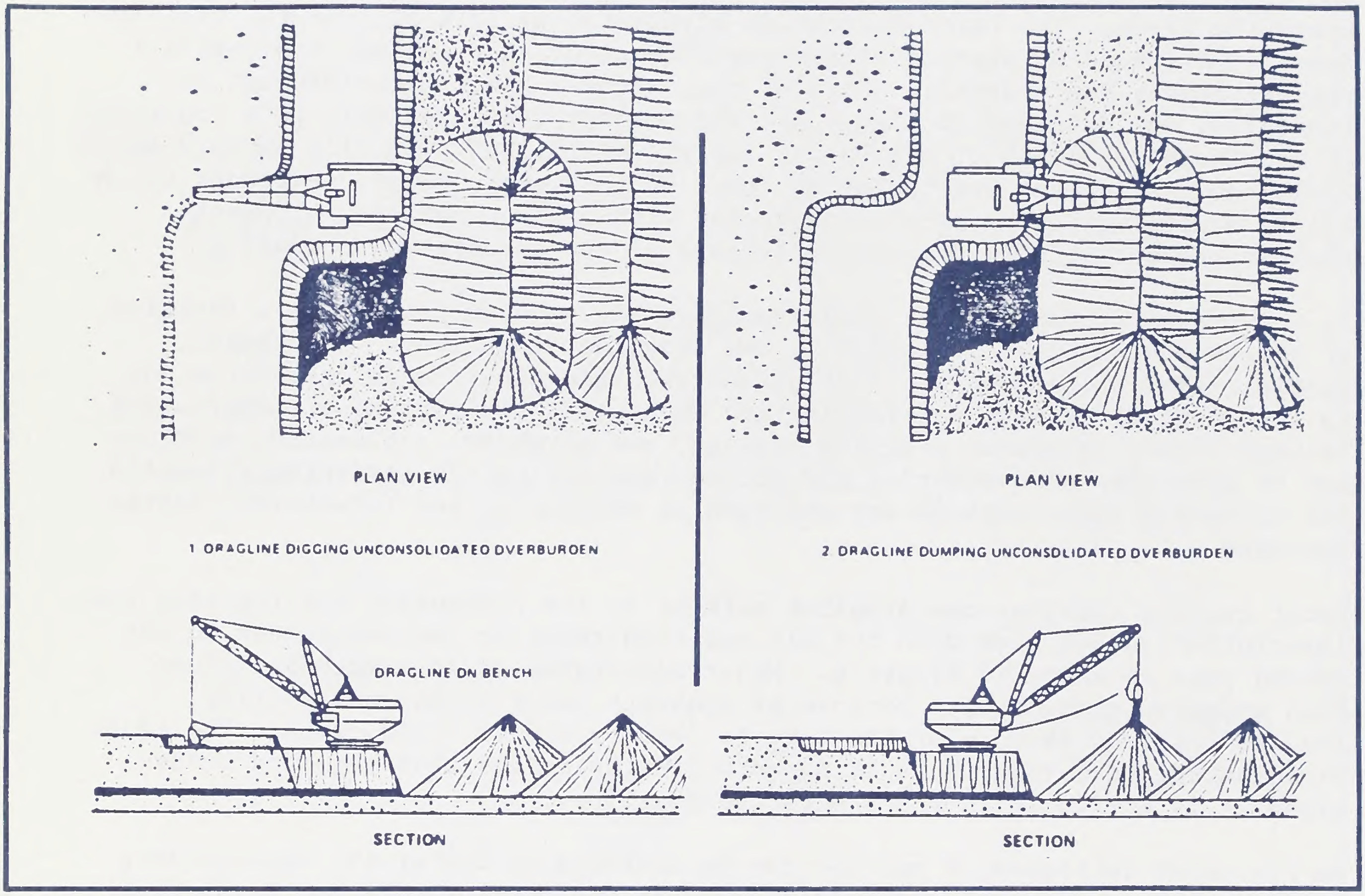
When overburden depths are even greater relative to dragline dimensions, the extended bench method is employed (Fig. 5). In this method, the reach that the dragline lacks is augmented by building out or extending the dragline operating bench. The reach deficit is eliminated by this build-out. The bench is extended by placing either regular-cut or chop-cut material against the previously dug highwall. Much of the extended bench material must be rehandled, as indicated in Figure 5. The percent rehandled will be a function of machine size, depth of overburden and pit width, but typically amounts to 25-40% of the inplace overburden in terms of bank cubic yards. Extended bench allows stripping deeper overburden depths with a given machine, although machine productivity is diminished because of the associated rehandling.

In a two-seam operation, the dragline operating mode will again be a function of the overburden depth relative to the dragline dimensions. In general, multiple-seam operations are less productive than single-seam operations due to increased difficulty in blasting and excavating the parting or interburden between seams, increased dragline walking, and potential reclamation problems due to inversion of overburden and interburden during the stripping operation. The following three methods are utilized as overburden and interburden depths increase.

Front casting involves the dragline working on the overburden and removing the interburden in one pass down the pit and then removing the overburden in the second pass as shown in Figure 6. Major advantages of this method include high dragline productivity because of moderate swing angles and walking requirements and absence of the need to level spoil or build ramps. The major disadvantages are that there is a depth limitation and that the interburden highwall is difficult to shape with the dragline.

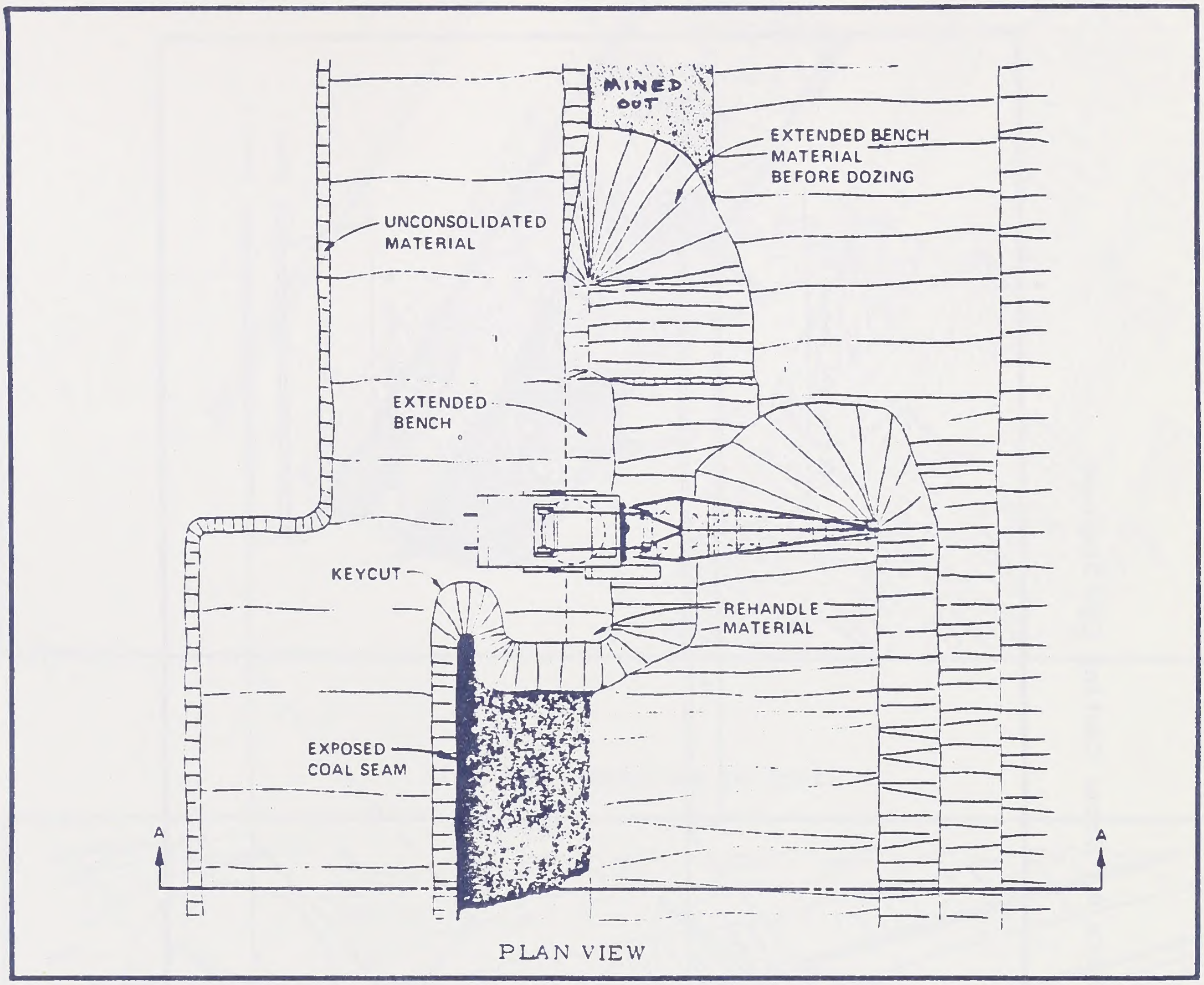
As the depth increases, a machine can be operated on top of the interburden, as indicated in Figure 7. A machine removes the overburden from the highwall and the same machine can then be ramped down to the top of the interburden to remove the interburden. Side casting is used for both cuts. Advantages of this method are that a dragline cuts the interburden highwall angle and that dragline productivity is relatively high because of conventional bucket loading and swing angles less than 90 degrees. Disadvantages include potential for spoil instability with all spoil dumped on the same apex, lack of stratigraphic control, and potential for low productivity with high hoist times and ramping requirements. As an alternative, a second machine can be permanently positioned on the interburden, thus eliminating the need for ramping.

Figure 4. Dragline Chopping Down

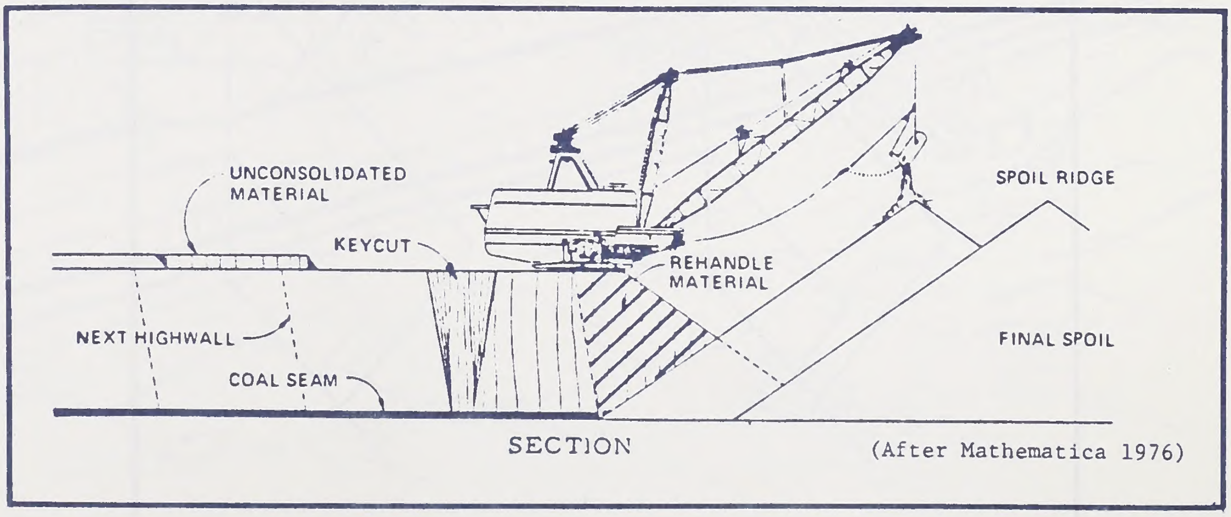

PLAN VIEW
1 DRAGLINE DIGGING UNCONSOLIDATED OVERBURDEN
DRAGLINE ON BENCH
SECTION
PLAN VIEW
2 DRAGLINE DUMPING UNCONSOLIDATED OVERBURDEN
SECTION

(After Mathematica 1976)

Figure 5. Dragline on Extended Bench.



PLAN VIEW



SECTION

(After Mathematica 1976)

Figure 6. Front Casting Cut Diagrams.

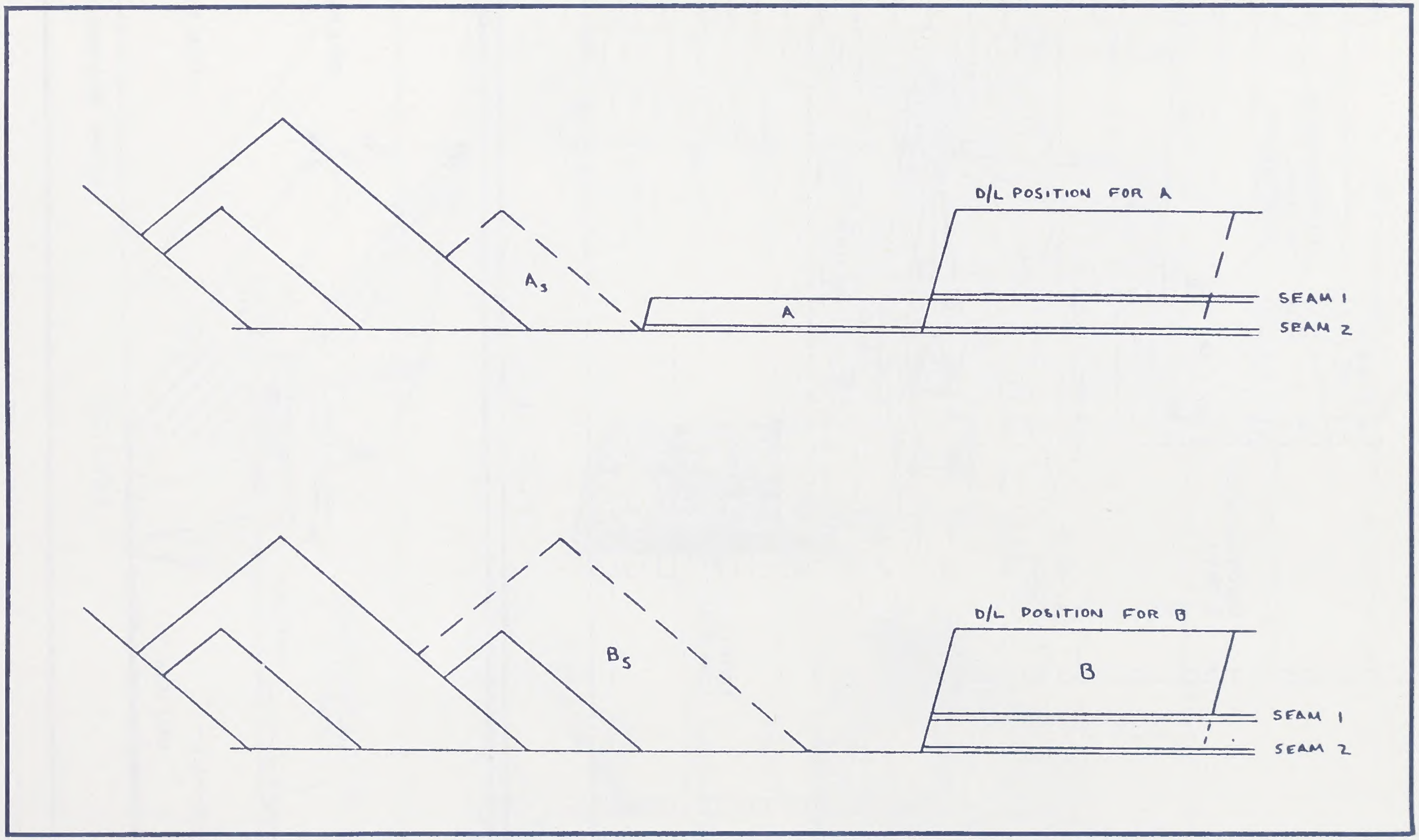


Figure 7. Dragline on Interburden

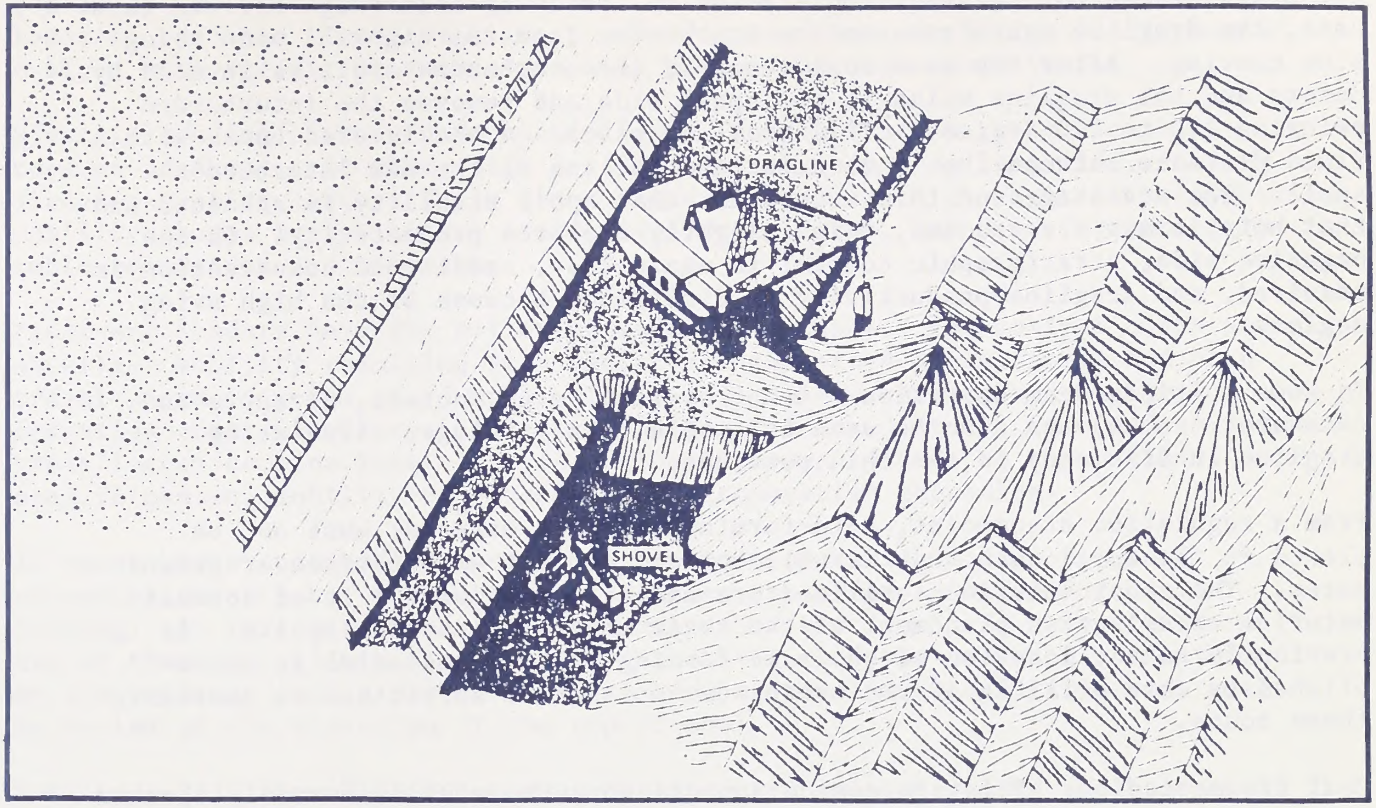
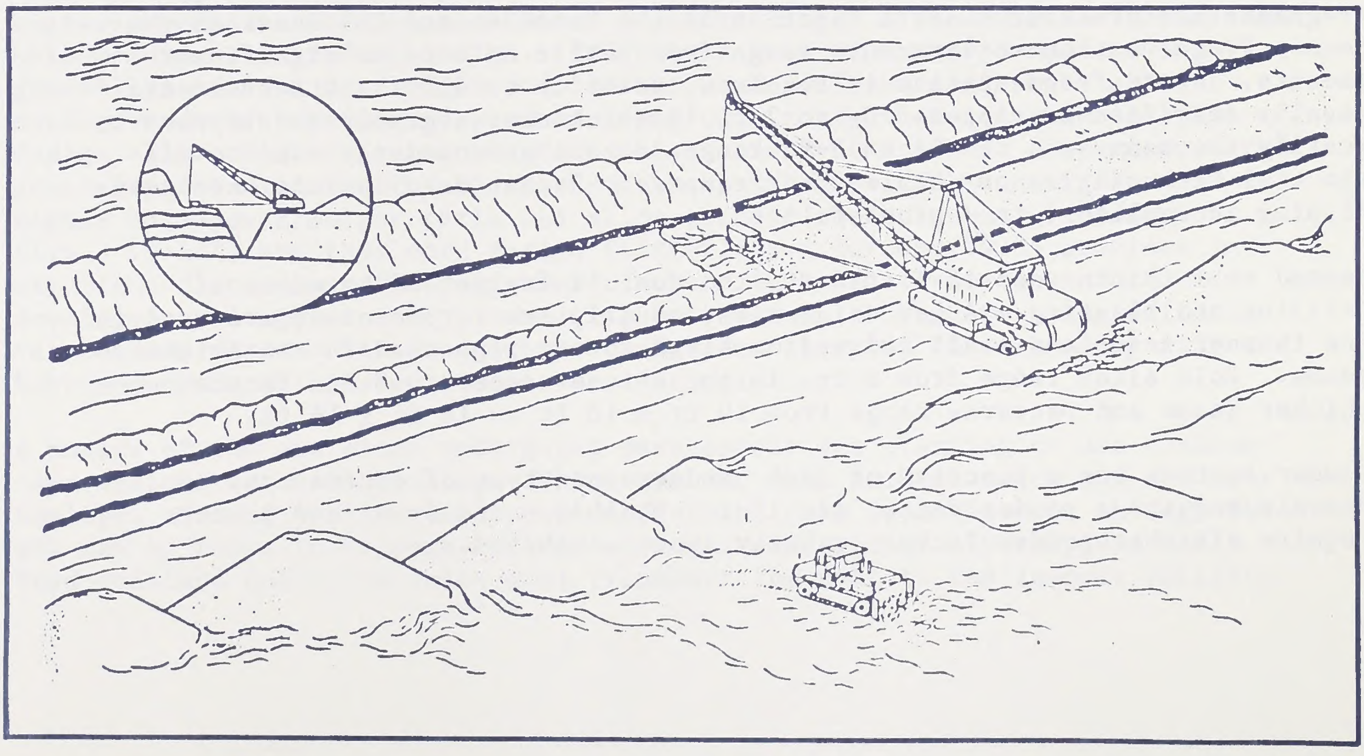


Figure 8. Dragline on Spoil



(After Mathematica 1976)

In deep overburden or where spoil benching is required for stability reasons, the dragline can be operated from a bench on the spoil side (Fig. 8). In this case, the dragline again removes the overburden from the highwall side using side casting. After top seam coal removal, the overburden spoil is leveled by dozers and the dragline walks to the spoil side and removes the interburden swinging 110 to 150 degrees. This spoil is placed on the leveled bench with a fixed distance between the bench crest and the toe of the new interburden spoil. The advantages of this method are that spoil stability is enhanced and that hoist times are reduced, which slightly improves productivity. On the negative side, stratigraphic control is again lost, spoil road construction is required, and dragline productivity is diminished because of the high swing angles.

In some multiple-seam operations, other systems (e.g., dozers, scrapers and excavator/trucks) can also be used to handle thin partings, alleviating dragline inefficiency in the thin partings.

From a regulation standpoint, acid-forming or toxic material must not be placed in the spoil such that it will come in contact with surface or groundwater. The usual solutions utilized are either burial with 4 ft of nontoxic material or selective placement of the toxic material into the spoils. As previously noted, location of the acid-forming or toxic material is accomplished by core drilling of the overburden on centers sufficient to delineate these zones.

Coal fragmentation: Prior to coal fragmentation, the coal is normally cleaned using a rubber-tired dozer. This machine removes the last remnants (i.e., 3-12 inches) of overburden left by the dragline. In some cases, particularly where hard, high-quality, thin seams are mined, street sweepers are employed to further clean the coal and reduce contamination.

Fragmentation procedures are a function of the hardness and thickness of the seam. Fragmentation requirements range from little or none to significant amounts. Where fragmentation is required, seams up to 5 ft in thickness are usually scarified or ripped. Up to 2 ft in thickness, a grader can be used to scarify the seam. In the 2- to 5-ft range, dozers are commonly used to rip the coal with single- or double-shank rippers. Recent developments have seen ripping accomplished to depths of 11 ft.

Beyond seam thicknesses of 5 to 6 ft, the coal is fragmented by means of drilling and blasting. Auger drill rigs, usually tractor-mounted, are used in the thinner seams and small and medium-sized rotary rigs used in the thicker seams. Hole sizes range from 2 in. in the thinner seams to 8 in. in the thicker seams and patterns range from 10 ft x 10 ft to 16 ft x 16 ft.

Powder factors are a function of coal hardness and type of excavators. Shovels require a powder factor of .15 to .25 lb/ton and front-end loaders require a higher powder factor, usually about .4 lb/ton.

Coal loading: Coal loading is usually accomplished either with large-capacity (to 50 cu yd) electric loading shovels or with large-capacity front-end loaders. Because of the relatively easy digging characteristics of fragmented coal, a wide variety of excavators will handle the unit operation.

Electric loading shovels have the following attributes: high productivity because of fast cycle time, high availability, high reach, long life, and low direct operating costs. Their major disadvantages are high capital cost, poor mobility caused by low travel speed (less then 1 mph), and need for power cable connection and movement.

Front-end loaders have the following major advantages: low capital costs and excellent mobility resulting from their self-contained diesel power and high travel speeds (excess of 15 mph). Their major disadvantages are higher operating costs, lower availability, and limited reach at the face and in some truck/loader combinations. The selection is normally made on the basis of seam thickness, mobility requirement, and comparative economics.

In cases where soft-bottom conditions preclude operating equipment, both excavator and truck, on the bottom, backhoes are often selected for coal loading. In this situation, both the excavator and truck can be operated on top of the coal, eliminating problems caused by the poor traction conditions on the bottom. Such a design can also be used to eliminate lift if coal must be hauled at the elevation of the top of coal.

Both hydraulic shovels and numerous designs of wheel excavators are being utilized in some operations for coal loading. These machines tend to provide higher productivity, although long-term cost effectiveness has not been proven to date.

Coal hauling: Coal hauling from the pit is usually accomplished with off-highway trucks in the 50- to 180-ton capacity range. Trucks are either of the bottom-dump or rear-dump design. Tractor-trailer type rear dumps are generally selected for longer and flatter hauls. These units have a lower horsepower/weight ratio and produce lower unit costs where terrain and pit design allow shallow haul road grades (i.e., less than 6-9%). Rear dumps are generally selected for the shorter and steeper hauls. These units have a higher horsepower/weight ratio and allow steeper roads in the pit design (i.e., 10-12%) and thus more design flexibility. Burton (1975) provides an excellent discussion of off-highway trucks. In a relatively new truck development, large-capacity, two-axle, bottom-dump trucks are being utilized in numerous western pits to combine the gradeability of the rear-dump with the bottom-dump capability of tractor-trailer units.

A number of the new mines undergoing development are planning to use combination systems for coal hauling. These systems will combine truck and conveyor haulage. Trucks will be used to transport the coal from the face through the pit and up ramps to hoppers located on the graded spoil. The hoppers will feed overland conveyors which will transport the coal to the loadout facility.

The hoppers will be relocated and the belts extended periodically as the mine advances to keep truck haul distances with economic limits. Such systems are being considered to substitute low-cost conveyor haulage for mobile equipment haulage. Truck haulage has become increasingly expensive as diesel and other oil-related costs have escalated. Current thinking keeps trucks in the system to maintain face haulage flexibility. Ultimately, portable conveyors may be utilized for this segment of coal haulage.

Major regulatory aspects of coal haulage will be discussed in a subsequent section on pit design.

Regrading: Regrading or striking-off the spoil is usually accomplished with large-horsepower dozers (i.e., 450 hp), and final grading is done with large graders. Regulations provide a number of general guidelines including:

- Restoration to approximate original contour.
- Elimination of highwalls.
- Restoration of natural drainages to the extent possible.
- Construction of final slopes not exceeding original slopes.
- Productivity equal or greater than pre-mining productivity.

In addition, the regrading must be done within 180 days or with regrading kept within four spoil ridges of the active pit.

Topsoil replacement or redistribution: As previously discussed, scrapers, dozers or loader/trucks are utilized in this operation with topsoil replaced continuously or from stockpile. Some preparation of the graded spoil, plowing, etc., is usually done to stabilize the topsoil bed. Traffic patterns are designed to prevent over-compaction of the bed.

Revegetation: Planting is accomplished either by hydroseeding or with conventional farm equipment and must be done as soon as practical with seed selection based on post-mining land use. Success is usually judged by comparison with a reference area, with production rated as some percentage of that area. Erosion must be controlled so that gullies or rills more than 9 inches in depth do not develop. A period of extended responsibility is involved (e.g., 10 years where rainfall is less than 26 inches annually).

Power Distribution

In area stripping operations, mine power is most often carried to the pit with cables run in from the highwall side of the pit. This method requires retreat of the power lines but prevents problems related to advancing lines through the spoil and reclaimed area. In recent years the trend toward higher horsepower stripping machines has dictated use of higher mine delivery voltages (e.g., 7.2 to 25 kV). In addidion, powerlines on the surface have replaced pole-line distribution systems because of lower installation costs.

A general mine power distribution system is shown in Figure 9. A main powerline is brought into the mine substation and transformed to a lower mine voltage. The mine powerline is run parallel to the pit and laterals on 1,000 to 1,500 ft centers are run to the pit perpendicular to the mine powerline. The laterals have skid-mounted junction boxes, breakers, and transformers if low-voltage equipment (e.g., pit pumps) is operated off the lateral. As the dragline strips the cut and reaches the extent of the trail cable, the trail cable is switched to the lateral in the direction of cut advance. When a number of cuts are finished, the laterals and skid-mounted breakers and transformers are retreated toward the mine powerline. Finally, when the operation approaches the mine powerline, the mine powerline is relocated by retreating it approximately 1 mile and the process is repeated.

Pit Design

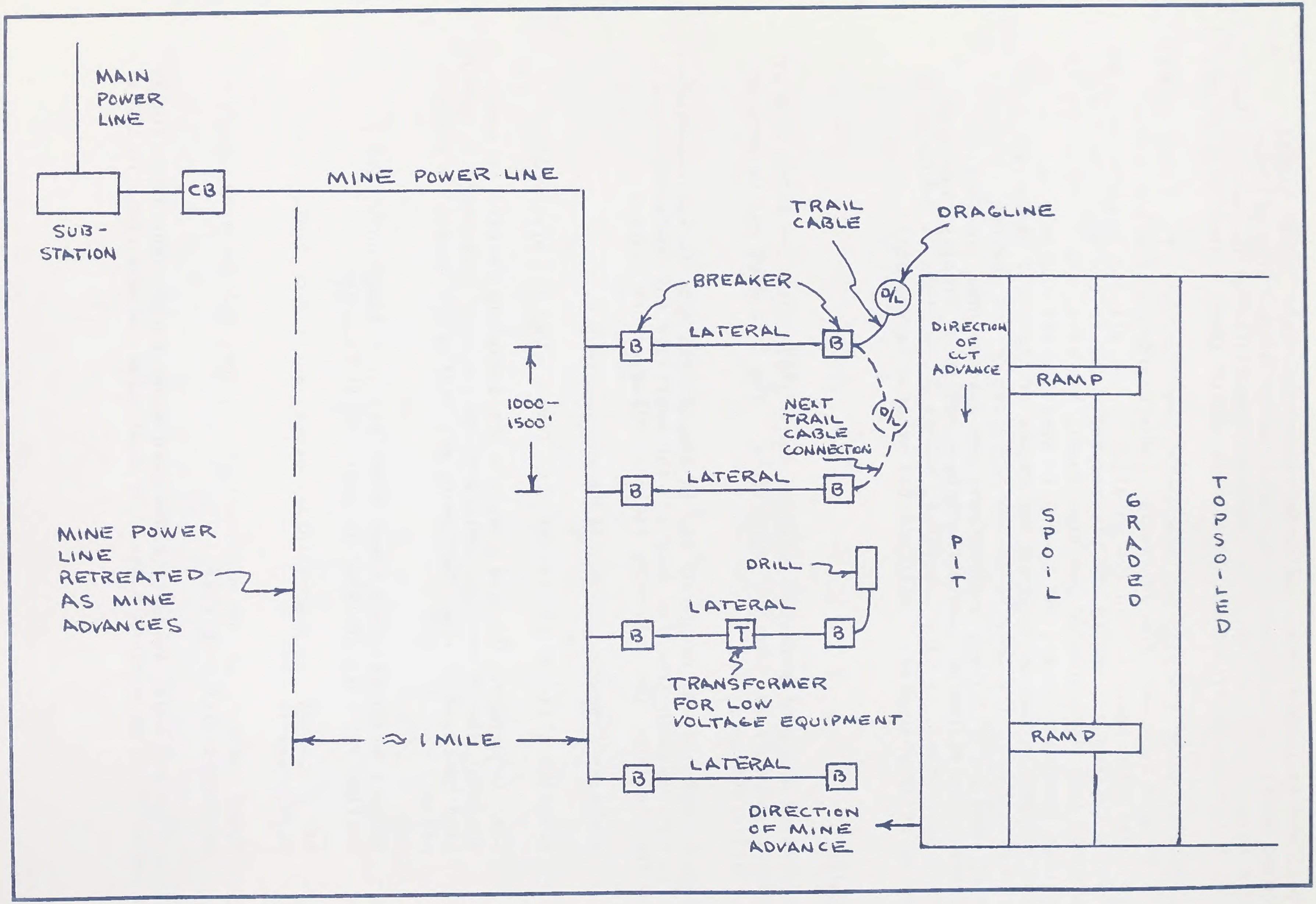
Pit parameters and configuration selected for a given site are a function of the deposit geometry and current regulations. The following points must be given consideration.

Pit length: The average length of pit in the central U.S. is approximately 5,500 ft, and although specific data are not available for the western U.S., lengths are similar. The following factors influence pit length:

- Property dimensions: Can limit maximum length.
- Dragline efficiency: Longer pits (over 3,000 ft) preferred.
- Coal inventory: In some cases, a pit inventory is kept to meet seasonal demand or compensate for low stripper availability; amount is a function of seam thickness, pit width, and length of block in place.
- Spoil instability: If spoil stability is a function of time, shorter pits are prefered to limit spoil failures.
- Pit flooding: In high-rainfall areas, short pits limit water quantities in pit.
- Power system: In low mine-voltage systems, voltage drop becomes excessive with long pits.

Pit width: The pit width in large midwestern mines ranges from 95 to 105 ft and averages 120 ft in western mines. In deep cover, widths range to 180 ft.

Figure 9. Sketch of Power System for Area Operation



The following factors influence pit width:

- Stripping machine reach: Strippers are limited by reach and therefore a limit is placed on the pit width and overburden depth combination if rehandling is to be avoided.

- Overburden depth and dragline productivity: Simulation studies indicate that narrow pits should be chosen in shallower overburden because of decreased swing angles, and that wide pits should be selected in deep overburden where extended bench is utilized to minimize percent rehandle ("Mathematica" 1976, Hrebar and Dagdelen 1979). These selections will improve dragline production.

- Reclamation: Narrow pits minimize spoil peak strike-off in regrading while wide pits increase spoil vee area and strike-off quantities.

- Coal loading and hauling: Some minimum width required for efficient equipment operation; width is a function of equipment size and type combinations.

- Coal inventory: Width will influence tonnage/lineal foot of pit.

Haul roads: The average haul road distance in the central U.S. is approximately 5 miles one-way. The haul roads are usually spaced on 1,500- to 1,800-ft centers through the spoil to facilitate one-way hauls if possible. In deeper overburden, fewer haul roads through the spoil may be used as a result of significant spoil volume losses. Where contemporaneous haul-road reclamation is required, the trend appears to be fewer haul roads through the spoil. In addition, there appears to be a trend toward steeper ramps. Both of these trends cause decreases in truck productivity because of increases in turnaround areas in the pit and increases in time spent hauling up ramps. Generally, these roads are located to minimize haul distance and designed to facilitate high-speed haulage using width and construction guidelines similar to those presented in IC 8758.

Two other haul road arrangements are used in certain situations. Highwall side ramps are used where spoil stability problems, spoil volume losses, or unusual property geometry are factors. The prime disadvantage of the highwall side ramps is the dragline inefficiency and auxiliary equipment time associated with continuous rebuilding as the mine advances. Pit end haul roads are used where spoil volume losses or spoil instability are factors. This requires unique pit geometry, cropline on three sides, or deep box cutting to maintain the access. Long in-pit haul distances are generally associated with pit-end haul roads.

The regulations dealing with haul road design are extensive. Road classes are established (i.e., coal haulage, access, and temporary access) and specifications of grades, sidehill embankments, culvert spacing, etc. are given for each road class. These design criteria are currently in litigation. In addition, the regulations call for durable material on all roads which will be used longer than 6 months. Bridge designs must meet certain flood criteria depending on span.

Mine drainage and erosion and sediment control: For many years, it has been good operating practice to divert surface water from active pit areas to eliminate in-pit water problems. Diversion ditch systems were utilized to deflect the water and direct it into natural drainages.

Under current regulations, this practice has been expanded to include the following:

- Surface drainage from disturbed areas must pass through a sediment pond.
- Effluent from the ponds must meet limitations on pH, iron, manganese, total suspended solids, etc.
- Sedimentation ponds must be constructed to standards on capacity, detention time, dewatering, location, slopes, etc.; these standards, particularly the capacity standards, have been contested by industry.
- Discharge compliance must meet 10-year, 24-hour precipitation events.
- Treatment is required if necessary to meet effluent standards.

General design measures taken to meet these standards economically include minimizing the disturbed area, stabilizing backfill, diverting overland flow around or through disturbed areas to reduce pond size, revegetating immediately to reduce sediment load, and separating pit water from other water to minimize treatment. Skelly and Loy (1979) have provided an in-depth treatment of drainage and erosion control.

Pit Orientation

Selection of the pit orientation and sequencing is critical to the mine plan, as it will determine equipment selection, operating costs relative to the production life, coal quality relative to the production life, etc.

Straight vs. curved pits: Where a property contains a curved outcrop or subcrop where stripping will begin, the operator must decide if the subcrop will be followed or whether straight pits will be employed. Where curved pits are selected, a series of inside and outside curves are usually encountered. The inside curves, where the advancing highwall arc is greater than the spoil side arc, can cause significant spoil room problems, particularly when overburden depth increases in the direction of mine advance. In this case, each new cut contains more overburden volume than is available in the prior cut spoil volume. Excess spoil is soon generated and costly rehandling is required.

Outside curves, with the advancing highwall arc less than the spoil side arc, can be used to an advantage in areas of increasing overburden depths. In this case, each new cut has less area than the adjacent spoil area, and this difference can be utilized to accommodate the added volume caused by the increase in overburden height. Outside curves can be used to advantage where an operation encounters ridges perpendicular to the cropline or subcrop.

In addition to the inside curve problem, curved pits are difficult to lay out in the field and difficult to execute from an operating standpoint. They also require coal haulage on curves in the confined pit. As a result of these problems, many operators choose to develop straight pits which alleviate these problems.

Straight pits are developed either by a series of short pits or by varying pit width. A series of short pits on the cords of an outside curve can be utilized to straighten the pits. In many cases, auxiliary equipment such as a scraper fleet will be used to strip these pits so that the dragline is not utilized until long, straight pits are available. This has the advantage of not applying the dragline in inefficient short pits and of postponing the dragline investment while low capital cost equipment is used to begin the operation. The other alternative is to utilize the dragline and employ wide pits at the outside curves and narrow pits at the inside curves until a straight pit configuration is achieved. This alleviates the short pit inefficiency but is more difficult to engineer, lay out, and execute. Bucyrus-Erie (1976) and Bonner and Moore (1977) provide an in-depth discussion of inside and outside curves.

Averaging vs. minimizing stripping requirements: Orientation of pits and pit sequencing are crucial to the entire mine planning scheme. The common alternatives are averaging and minimizing the stripping ratio over time.

When the ratio is averaged, approximately the same stripping ratio and the same quantity of overburden are handled each year. Overburden depths range from low to high in a given year to balance and average the ratio. The advantages of this approach include fairly constant stripping capacity requirements, constant costs/ton (exclusive of inflationary effects), and constant manpower requirements.

When the ratio is minimized, areas with the low stripping ratio are mined in early years, mid-range ratio in mid years, and high ratio in later years. These plans must also consider such constraints as minimum pit lengths, avoidance of excessive dragline walking by selecting a logical progression through the property, and allowance for efficient haul road access. The primary advantage of this approach is that the best economics are generally achieved because of postponement of capital expenditure and low direct operating costs in early years of production. However, the disadvantages include continually increasing equipment and manpower requirements in order to strip increasing amounts of overbruden. Management of the constantly changing operation is more difficult. However, the economic benefits of minimizing stripping ratio are significant, as will be described in the case study in the final section.

Dragline Selection

Selection of a dragline which will meet the production requirements for a particular project is a two-part problem requiring determination of the reach and capacity required and then selection of the proper model to meet these specifications. A simple example will be presented to illustrate the concepts.

Reach: The reach required on a given property is the distance from the highwall crest to the spoil peak, as illustrated in Figure 10. Note that this dimension is independent of the dragline and is a function of the parameters listed in Figure 10. Reach can be determined analytically as in Figure 10 or graphically by construction of cut diagrams (see Hrebar, et al. 1981). To illustrate the analytical solution, assume the following values: $H = 100$ ft, $W = 100$ ft, $\phi = 71.6°$, $\theta = 38.7°$, $S = 35\%$, $t = 10$ ft.

$$r = 100\ [\cot 71.6 + \cot 38.7\ (1 + 35/100)] + \frac{100}{4} = 227 \text{ ft.}$$

This reach is usually adjusted upward to account for the two-dimensional approximation of a three-dimensional problem and the required reach would be a minimum of 237 ft.

Capacity: Dragline capacity, for machine selection purposes, is expressed in terms of maximum suspended load in pounds. Maximum suspended load consists of the weight of the bucket and the weight of the material in the bucket.

A general excavator output equation is shown in Table 6. As seen there, the output of a machine can be expressed as a function of the bucket size and a number of other parameters. An example is given to show the output of a 100 cu yd machine. The equation can be rearranged to solve for the required bucket size if a specified output is required, as shown in the last equation in Table 6. This is usually the case for a property where coal requirements and stripping ratio are fixed. Bucket size is calculated in Table 7 for an example where 2,000,000 tons/year of coal is required from a property with an average of 100 ft of overburden. The indicated bucket size is 67.4 cu yd. At this point, an additional allowance is normally made for production margin, haul road rehandle, etc. In the example, a bucket size of 74 cu yd would be used to calculate maximum suspended load.

Assuming a material density of 3,400 lb/cu yd in place and a bucket weight of 2,219 lb/cu yd, the maximum suspended load would be calculated as follows:

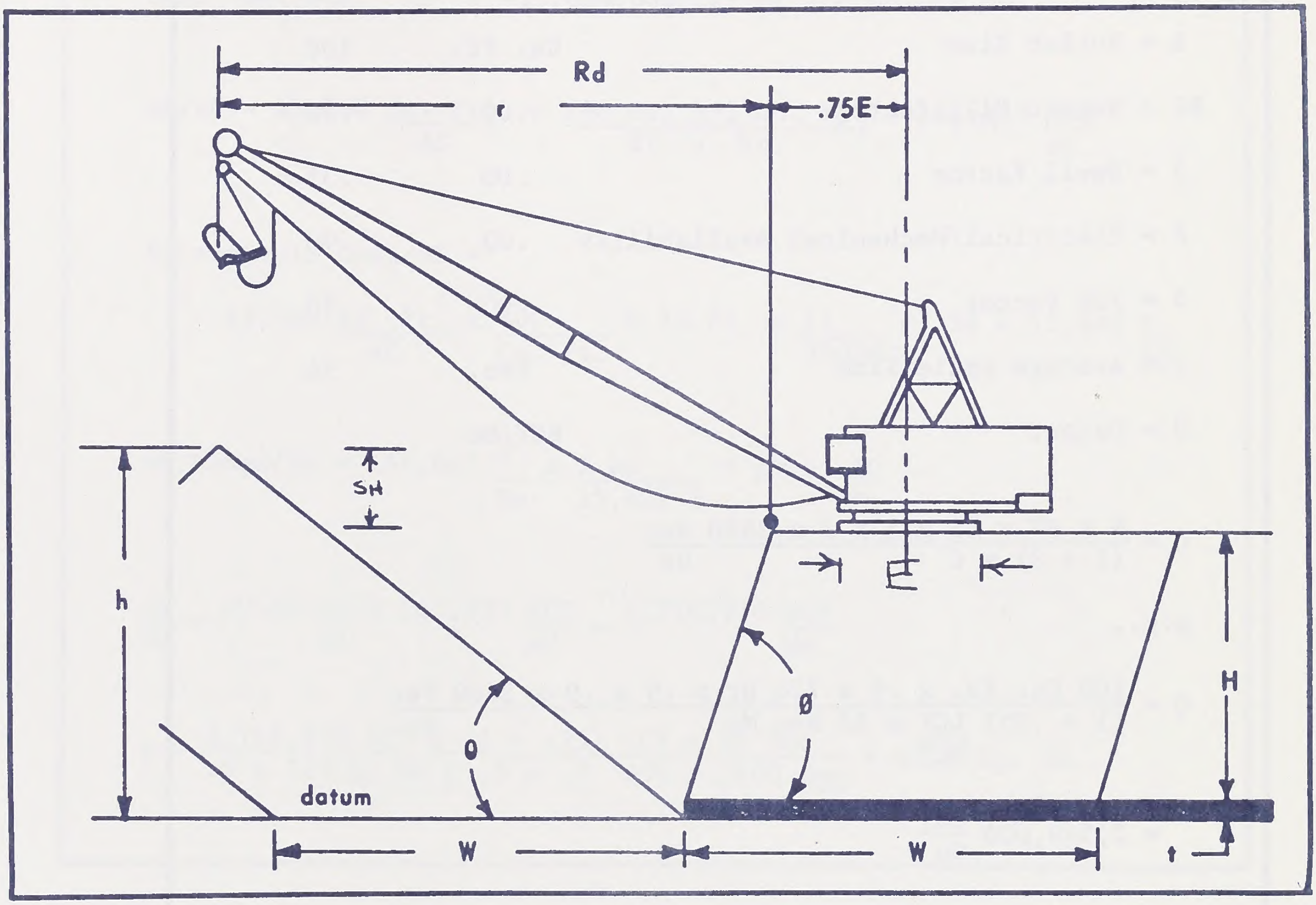
$$\text{Material:} \quad 74 \text{ cu yd} \times \frac{3{,}400 \text{ lb}}{\text{BCY}} \times \frac{1}{1.35} = 186{,}370 \text{ lb}$$

$$\text{Bucket:} \quad 74 \text{ cu yd} \times \frac{2{,}219 \text{ lb}}{\text{cu yd}} = \underline{164{,}206 \text{ lb}}$$

$$\text{Maximum suspended load} \quad 350{,}576 \text{ lb}$$

Figure 10. Analytical Reach Determination

Given:
H = Overburden Thickness
W = Pit Width
ϕ = Highwall Angle
Θ = Spoil Angle
S = Swell in %
t = Coal Thickness



$$\text{Reach} = r = \text{Cot}\ \phi \times H + \text{Cot}\ \Theta\ [(1 + S/100) \times H + W/4 \times \text{Tan}\ \Theta\ ] \ \underline{\underline{\text{or}}}$$

$$= H\ [\text{Cot}\ \phi + \text{Cot}\ \Theta \times (1 + S/100)] + W/4$$

$$\text{Operating Radius} = Rd = r + .75E$$

Where E = Tub Diameter

$$\text{Height of Spoil} = h = (1 + S/100) \times H + W/4 \times \text{Tan}\ \Theta$$

$$\text{Stacking Height} = SH = h - t - H$$

NOTE: For side casting in straight pit in this configuration with 90° coal angle only.

(After Ferko 1974)

Table 6. Excavator Output and Bucket Capacity Equations

	Units	Example
HS = Hours Scheduled/Month	Hr/Mo	720
B = Bucket Size	Cu. Yd.	100
BF = Bucket Fill Factor	.00	.90
S = Swell Factor	.00	.35
A = Electrical/Mechanical Availability	.00	.90
J = Job Factor	.00	.90
C = Average Cycle Time	Sec.	55
0 = Output	BCY/Mo	

$$0 = \frac{B \times BF \times HS \times A \times J \times 3600\ \frac{\text{Sec}}{\text{Hr}}}{(1 + S) \times C}$$

e.g.,

$$0 = \frac{100\ \text{Cu. Yd.} \times .9 \times 720\ \text{Hr} \times .9 \times .9 \times 3600\ \frac{\text{Sec}}{\text{Hr}}}{(1 + .35)\ \frac{\text{LCY}}{\text{BCY}} \times 55\ \text{Sec Mo}}$$

$$\cong 2{,}549{,}000\ \frac{\text{BCY}}{\text{Mo}}$$

Given 0 in BCY/Mo, rearrange and solve for bucket capacity.

$$B = \frac{0 \times (1 + S) \times C}{BF \times HS \times A \times J \times 3600\ \frac{\text{Sec}}{\text{Hr}}}$$

Table 7. Example of Bucket Capacity Determination

Avg. Overburden Depth = 100 ft.
Coal Thickness = 10 ft.
Coal Density = 80#/Cu. Ft.
Recovery = 90%

Coal Contract = 2,000,000 TPY or 166,667 TP Mo.

$$\text{OB/AC} = 43{,}560 \ \frac{\text{Sq. Ft.}}{\text{AC}} \times \frac{100 \text{ Ft.} \times 1 \text{ Cu. Yd.}}{27 \text{ Cu. Ft.}} = 161{,}333 \ \frac{\text{BCY}}{\text{AC}}$$

Recoverable Coal/AC =

$$43{,}560 \ \frac{\text{Sq. Ft.}}{\text{AC}} \times \frac{80\#}{\text{Cu. Ft.}} \times 10 \text{ Ft.} \times \frac{1\text{T}}{2000\#} \times .90 = 15{,}682 \ \frac{\text{T}}{\text{AC}}$$

$$\text{AC Mined/Mo} = 166{,}667 \ \frac{\text{T}}{\text{Mo}} \times \frac{1 \text{ AC}}{15{,}682 \text{ T}} = 10.63 \ \frac{\text{AC}}{\text{Mo}}$$

$$\frac{\text{OB}}{\text{Mo}} = 10.62 \ \frac{\text{AC}}{\text{Mo}} \times 161{,}333 \ \frac{\text{BCY}}{\text{AC}} = 1{,}714{,}970 \ \frac{\text{BCY}}{\text{Mo}}$$

$$B = \frac{1{,}714{,}970 \text{ BCY} \times (1 + .35) \text{ LCY} \times 55 \text{ Sec}}{.9 \times 720 \ \frac{\text{Hr}}{\text{Mo}} \text{ Mo} \times .9 \times .9 \ \text{BCY} \times 3600 \ \frac{\text{Sec}}{\text{Hr}}} = 67.4 \text{ Cu. Yd.}$$

For estimating purposes, a combined weight of bucket and material is often used. In the example, the bucket weight/cu yd was taken from a graph of bucket weight/cu yd vs. bucket size and provides a more accurate estimate (Hrebar et al. 1981, p. D-24). It should be noted that the maximum suspended load must be based on the heaviest overburden horizon when swell factor is considered to insure against overloading the machine selected.

After reach and maximum suspended load are estimated (e.g., 237 ft and 350,576 lb in example), dragline manufacture specifications can be reviewed to select a machine most closely matching this combination of requirements. For example, if Bucyrus-Erie machines were considered, the choice would range from a 1570-W (236.5-ft reach and 345,000-lb MSL) to a 2560-W (242.5-ft reach and 400,000-lb MSL). The final selection would be made after consideration of the ability of the smaller machine to meet production, the need for the excess capacity afforded by the larger machine, the potential for increased production, and the not insignificant capital cost difference of approximately $6 to $7 million.

The above example of dragline selection should be considered preliminary in nature. A final selection is done in much more detail and is beyond the scope of this paper. However, the following factors would be considered in the final selection procedure:

- Changing overburden characteristics: Analyze overburden to ascertain changes in highwall angle, spoil angle, swell factors, and effects on machine selection.

- Changing overburden depths: Ascertain that maximum machine digging depths are satisfactory and that coal production can be sustained through deep cover areas with proposed methods.

- Stacking height: Ascertain that stacking height is satisfactory at maximum overburden depths.

- Bearing pressures: Ascertain that machine bearing pressures are in line with bench material specifications (after Bucyrus-Erie 1976).

Selection of Other Equipment

Selection of equipment for other unit operations must be compatible with the method of stripping and the equipment employed for stripping. On a unit operation basis, a comparison of advantages and disadvantages can be used to refine or limit the types of equipment considered. In addition to these comparisons, equipment rating tables can be used to narrow the number of possible equipment systems for a particular unit operation. Skelly and Low (1975) have developed a set of tables for surface coal mining where a number of key considerations are provided for each unit operation, and each candidate equipment type or combination is ranked relatively for each consideration. As an example, the rating table for topsoil removal is shown in Table 8.

Table 8.

EQUIPMENT RATING-TOPSOIL REMOVAL

LEGEND

1. Should be considered
2. May be considered
3. May be considered under certain conditions.
4. May be considered special situation

A. High
B. Moderate
C. Low

		Dozers	Front-End Loaders	Scrapers			Dragline	Shovel & Truck	Bucket Wheel Excavator	Front-End Loader & Truck
				Elevating	Full-Power	With Push Tractor				
Topsoil Thickness	0-2'	1	1	1	1	1	3	–	–	1
	2'-5'	1	1	1	1	1	3	4	3	1
Haul Distance	0-300'	1	1	2	2	1	3	–	–	–
	300'-500'	2	2	1	1	1	4	–	3	–
	500'-1000'	–	–	1	1	1	–	4	–	3
	1000'-1500'	–	–	1	1	1	–	4	–	2
	1500'-5000'	–	–	2	2	2	–	4	–	1
Flexibility Under Varied Field Conditions	good	A	A	A	A	A	A	A	B	A
	fair	A	A	A	A	A	A	B	B	B
	poor	B	B	B	B	B	A	C	C	C

(Skelly and Loy - 1975)

Regardless of the methods used to arrive at candidate systems for a given unit operation, the ultimate selection will be made on the basis of comparative economics. These studies are usually designed to establish a comparative cost/unit or annual cost with the method selected having the lowest cost. Cost includes an allowance for both direct operating and ownership or capital costs.

In the course of selecting equipment, production and capital and operating costs must be estimated. To illustrate, consideration will be given to coal loading shovels and coal haulers, as a detailed treatment of each candidate piece of equipment for each unit operation is well beyond the scope of this article.

Coal Loading Shovels

Loading shovel selection is dependent upon production requirements and reach and related seam thickness. Production is usually calculated by using the standard formula for cyclic excavators:

$$O = \frac{B \times BF \times D \times HS \times A \times J \times 3{,}600 \text{ sec}}{(1+S) \times C \qquad \text{hr}},$$

where O = output, tons/shift
B = dipper size, CY
BF = bucket fill factor, %
D = in-place density, tons/CY
HS = hours scheduled/shift, hr/shift
S = material swell, %/100
A = electrical-mechanical availability, %/100
J = job factor, %/100, and
C = average cycle time, seconds.

Results of this type of analysis for coal loading applications as provided by an equipment manufacturer are shown in Table 9. Variable values might be considered typical and suggested average output can be used to arrive at a first approximation in shovel sizing. A number of comments pertain to Table 9:

- Cycle time increases with model or nominal bucket size.
- Cycle time increases with long range shovels of a given model.
- Electrical/mechanical availability is fairly high (91%) in the relatively easy coal loading application.
- Job factor corresponds to job efficiency measured on a minute/hour basis.

Table 9. Estimated Production Rate and Selected Specifications - Coal Loading Shovels.

	155-B	155-B	195-B	195-B	195-B	280-B	280-B	280-B	295-B	295-B	195-B
	STD[*1]	LR	STD	LR	SLR	STD	LR	SLR	STD	LR	SLR
Dipper Size, Cu. Yd.	14.0	13.0	20.0	18.0	16.0	24.0	21.0	17.0	30.0	24.0	19.0
Dipper Load											
Fill Factor	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Tons[*2]	11.54	10.72	16.49	14.84	13.19	19.78	17.31	14.01	24.73	19.78	15.66
Avg. Cycle Time, Sec.	24.8	26.2	26.3	29.0	32.0	28.0	30.0	33.7	30.0	32.0	34.0
Est. Maximum Excavation Rate, TPH	1,610	1,473	2,257	1,842	1,484	2,543	2,077	1,497	2,968	2,225	1,658
Est. Avg. Loading[*3] and Haul Rate, TPH											
Per Scheduled Hr.	1,099	1,005	1,540	1,257	1,013	1,736	1,418	1,022	2,026	1,519	1,132
Per 7.5 Hr. Shift	8,241	7,540	11,553	9,429	7,596	13,017	10,632	7,663	15,192	11,389	8,487
Max. Cutting Ht., Ft. (D)	37.5	47.0	41.7	55.5	-	43.7	-	60.0	49.0	-	-
Max. Dumping Ht. Ft. (A)	22.2	33.0	26.2	40.5	-	27.2	-	46.5	30.7	-	-
Boom Length, Ft.	37.5	52.0	41.5	56.5	70.0	50.0	60.0	80.0	40.0	70.0	85.0

*1 STD = Standard, LR = Long Range, SLR = Special Long Range

*2 Based on 1570 lb./Loose Cubic Yard

*3 75% Job Factor, 91% Electrical/Mechanical Availability

Reach considerations are important if coal haulers are placed higher than the standard bottom of coal elevation. As seam thickness increases with a need to place coal haulers on top of coal, a comparison of the combined height of coal plus height of truck must be made with the maximum dumping height. The proper boom length and machine model is selected to accommodate the combined height.

The number of units required can be estimated by dividing the total tonnage requirement/shift by the estimated loading and hauling rate. Once the number of shovels is selected, the operating and capital costs can be estimated.

Shovel operating costs consist of labor, power and repair, maintenance, and supply (RMS) components. Labor costs usually include an operator and oiler (if required) charged to the machine at the prevailing wage rate with an additional allowance (usually 35-40%) for fringe benefits. Power costs are based on consumption data provided by the equipment supplier, and are charged to the machine using the local rates including energy and demand charges. Typical consumption figures for standard boom length machines are as follows:

Dipper Size (CY)	Power Consumption (kWh/hr)
14	275
20	390
24	500
30	620

RMS charges include all supplies, parts and labor required to keep the machine operating and are generally the most difficult to estimate. It is generally accepted that a long-term average RMS cost can be obtained by allowing 10% of the total capital investment/year. The sum of the three components is the direct shovel operating cost.

Ownership costs are calculated by summing the charge for depreciation and interest, insurance, and taxes. The depreciation component is based on the capital cost/operating life (usually 20 years for loading shovels). The capital cost includes cost f.o.b. factory plus transportation plus erection. The interest, insurance, and tax (I.I.T.) component is calculated on the basis of a % I.I.T. times the average annual investment. The average annual investment is defined as:

$$\text{Capital cost} \times \frac{N + 1}{2N},$$

where N is the life of the shovel.

The total ownership cost on an annual basis can then be translated in cost/hour or cost/ton by dividing by the appropriate unit. Many companies use more sophisticated methods to better reflect the costs of ownership and operation. These methods include after-tax cost analysis and annual cost, which considers the effects of time value of money and tax considerations. Standard engineering economy texts such as Grant et al. (1976) present in-depth treatment of these methods.

Coal Haulers

Estimation of production of all mobile haul equipment follows the same basic procedures. The prime mover through engine, drive train, wheels, etc. delivers a force which propels the haul vehicle plus load. The rate at which the vehicle can cycle and deliver the load is the production of the unit.

The force that the drive wheels deliver to the ground is referred to as rimpull. This force is a function of the torque developed by the engine, the ratio of the gears, and the size of the wheels. Maximum velocity of a vehicle is achieved when rimpull equals the resisting forces of gravity, rolling resistance, etc. Available rimpull can be expressed as follows:

$$\text{Available rimpull} = \frac{\text{HP} \times 375 \times \text{E}}{\text{Speed in MPH}},$$

e.g., E = 85% for step gear and clutch transmission
= 75% for converter power-shift transmission
= 85% for converter power-shift transmission in lock-up.

For a given vehicle, a combination of the above elements is represented by the rimpull vs. velocity curve.

Vehicle performance is limited by a number of factors:

- Rolling resistance: Force required to overcome internal bearing friction and retarding effect between tires and ground caused by tire penetration and flexing.
- Grade resistance: Force required to overcome gravity when moving uphill.
- Weight: Determines force required to propel vehicle.
- Traction: Force delivered can be limited by traction conditions.
- Altitude: Decrease in air density may cause decrease in engine performance because of changes in fuel/air ratio.
- Speed limits: Commonly set on curves, in pit and on main haul roads for safety and maintenance reasons.
- Acceleration, deceleration, operator: Theoretical speeds from performance curve or computer simulation must be corrected for operator performance; from performance curves, these speeds must be corrected for acceleration and deceleration.
- Tires: Limit capability by limiting load and speed.

These limiting factors must be considered in developing estimates of vehicle cycle time, which consists of variable travel time (haul and return) plus fixed time (load, dump and spot).

To illustrate the procedures, production will be estimated for the haul shown in Figure 11 using 150-ton bottom dump trucks. Haul and return times are a function of payload, vehicle weight, HP/weight ratio, rolling, and grade resistances. Calculation for use of performance curves and speed factors (used to account for acceleration and deceleration) are shown in Table 10.

Haul road segment length, grade resistance, and rolliing resistance are listed in Table 11. A maximum speed for each segment is obtained from the truck performance chart (rimpull vs. velocity curve) and inserted in Table 11. A speed factor is obtained to arrive at the average speed for the segment. Haul and return times are then calculated as indicated in Table 11 for each segment and summed for all segments.

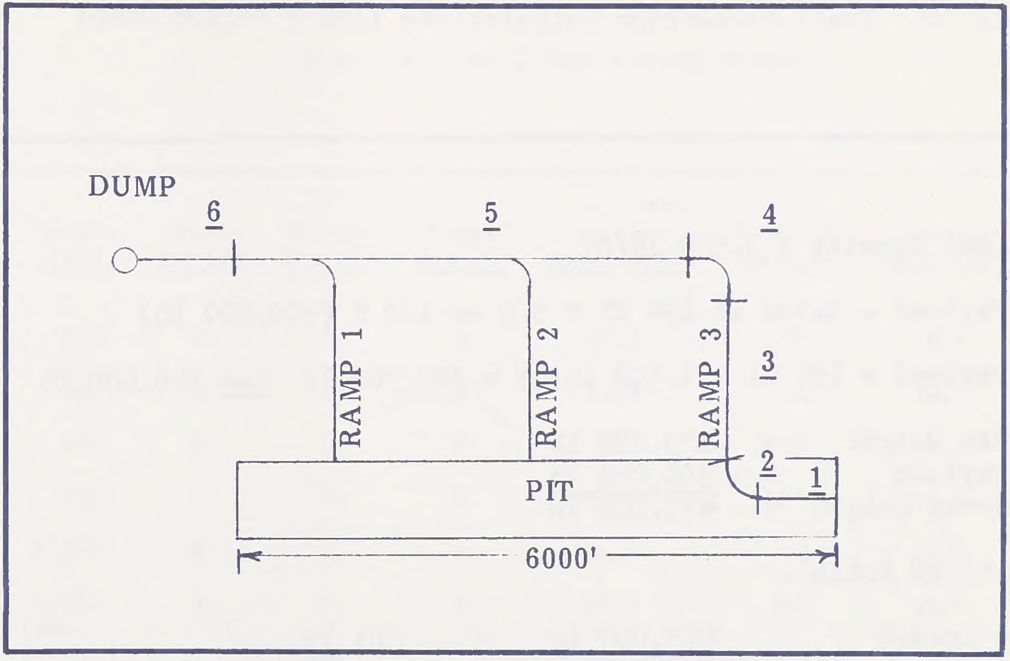
The next step in the process involves completion of the truck cycle time calculations as shown in Table 12. Haul and return times are ususlly adjusted for operator performance, loading time is calculated, and other fixed times are added.

Calculation of unit production, units required, and trucks/loader is shown in Table 13, assuming a coal requirement of 12,000 tons/shift. Consideration of operating efficiency and mechanical availability is included in unit production and units required, respectively. Operating efficiency reflects delays resulting from loader moves, blasting, weather, traffic congestion, auxiliary equipment delays, queuing at the loader, servicing, personnel delays, job layout, supervision, etc., and is used to arrive at long-term average production. Mechanical availability is the percent of scheduled time that a truck is mechanically ready to operate and is used in the calculations to provide standby equipment when trucks are not operating to ensure that production is met on the specified schedule. Maximum trucks/loader is checked to ascertain if the loader possesses sufficient capacity to service the operating fleet.

Costs for the truck fleet would again include allowances for operating and ownership costs. Operating costs include the components of fuel, lubrication, maintenance and repair, tires, and labor with an appropriate addition for fringes. Ownership costs again include a charge for depreciation and interest, insurance, and taxes based on average annual investment. The capital cost for depreciation purposes includes the cost f.o.b. of the truck plus freight less the tire costs, which are treated in operating costs. Total haulage costs would be calculated by determining total truck operating hours and multiplying by the cost per operating hour.

For a more detailed analysis of truck production and cost calculations, see Gessel (1977).

Figure 11. Haul Road Sketch
(Plan - Not to Scale)



	Haul Road Segments	Length	Grade	Rolling Resistance	Speed Limit
1	Shovel to Curve	900'	0%	80 lb/T	20 MPH
2	Curve to Ramp	200'	0%	60 lb/T	12 MPH
3	Ramp to Curve	900'	5%	60 lb/T	20 MPH
4	Curve to Main Haul Road	800'	0%	40 lb/T	30 MPH
5	Main Haul Road	4,500'	0%	40 lb/T	35 MPH
6	Main Haul Road to Dump	1,000'	0%	40 lb/T	35 MPH

Table 10. Truck Production Calculations (150 T Bottom Dump)

Loose Coal Density = 1,550 lb/CY

Check Payload - Rated at 194 CY @ 3:1 or 150 T (300,000 lb)

Payload = 194 CY x 1,550 lb/CY = 300,700 lb use 300,000 lb

Net Weight	=	175,000 lb
Payload	=	300,000 lb
Gross Weight	=	475,000 lb

Weight to HP Ratio -

- Loaded $\dfrac{475{,}000 \text{ lb}}{940 \text{ HP}} = 505 \dfrac{\text{lb}}{\text{HP}}$

- Empty $\dfrac{175{,}000 \text{ lb}}{940 \text{ HP}} = 186 \dfrac{\text{lb}}{\text{HP}}$

Check Traction -

- Governed by ramp, weight on drive axle = 196,650 lb
  Coefficient of traction on firm earth = .60

  Usable Rimpull = .60 x 196,650 lb = 117,990 lb
  Available Rimpull 37,000 lb

Table 11. Haul and Return Times.

Haul Road Segment	Length (Ft)	Grade Res (%)	Rolling Res (%)	Total Res (%)	Maximum Speed (MPH)	Speed *1 Factor	Average Speed (MPH)	Haul Time *2 (Min)
Loaded:								
1	900	0	4	4	13.5	.51	6.9	1.48
2	200	0	3	3	18.8	.55	10.3	.22
3	900	5	3	8	7.3	1.00	7.3	1.40
4	800	0	2	2	26.0	.49	12.7	.72
5	4,500	0	2	2	26.0	.93	24.2	2.11
6	1,000	0	2	2	26.0	.67	17.4	.65
Total Haul Time								6.58
Empty:								
6	1,000	0	2	2	44.0	.67	28.8	.39
5	4,500	0	2	2	44.0	.95	35.0 *3	1.46
4	800	0	2	2	44.0	-	20.0 *3	.45
3	900	-5	3	-2	44.0	-	20.0 *3	.51
2	200	0	3	3	44.0	-	12.0 *3	.19
1	900	0	4	4	20.0 *3	.64	12.8	.80
Total Return Time								3.80

*1 Table 4

*2 Haul Time (Min) = $\frac{\text{Segment Length (Ft)}}{\text{Avg Speed (MPH)} \times 88 \text{ (Ft x Hr/min x mi)}}$

*3 Limited by Speed Limit

Table 12. Truck Cycle Time Calculations

Haul and Return Time:

	Performance Curve Time	Average* Time
Haul	6.58	7.74
Return	3.80	4.47

*Average Time = Performance Curve Time/.85

Load Time:

Assume - Loaded by 30 CY Shovel with 30.0 sec Cycle Time with 95% Fill Factor

$$\text{Tons/Cycle} = \frac{30\text{ CY}}{\text{Cycle}} \times .95 \times \frac{1{,}550\text{ lb}}{\text{CY}} \times \frac{1\text{ T}}{2{,}000\text{ lb}} = 22.1\ \frac{\text{T}}{\text{Cycle}}$$

$$\text{Cycles/Truck} = \frac{150\text{ T}}{\text{Truck}} \times \frac{1\text{ Cycle}}{22.1\text{ T}} = 6.8 \text{ or } 7 \text{ Cycles}$$

$$\text{Loading Time} = 7 \text{ Cycles} \times \frac{30\text{ sec}}{\text{Cycle}} \times \frac{1\text{ min}}{60\text{ sec}} = 3.50\text{ min}$$

Truck Cycle Time

Load	3.50 min
Haul	7.74 min
Dump	.50 min
Return	4.47 min
Spot	1.30 min
Total Cycle Time	17.51 min

Table 13. Unit Production, Units Required and Trucks/Loader

Unit Production

Assume - 7.5 hr/shift, 1 shift/day, 50 min hour, 85% availability

$$150\ \frac{T}{\text{Cycle}} \times \frac{1\ \text{Cycle}}{17.51\ \text{min}} \times \frac{50\ \text{min}}{\text{hr}} \times \frac{7.5\ \text{hr}}{\text{shift}} \times \frac{1\ \text{shift}}{\text{day}} = 3{,}212\ \frac{T}{\text{shift}}$$

Units Required

$$12{,}000\ \frac{T}{\text{shift}} \times \frac{1\ \text{unit-shift}}{3{,}212\ T} = 3.74 \text{ or } 4 \text{ units operating}$$

Considering availability,

$$\frac{3.74\ \text{units}}{.85} = 4.40 \text{ or } 5 \text{ units purchased}$$

Maximum Trucks/Loader

$$\text{No Trucks} = \frac{\text{Truck Cycle Time}}{\text{Load Time}} = \frac{17.51\ \text{min}}{3.50\ \text{min}} = 5.0\ \text{Trucks}$$

or based on match factor, Match Factor = 1 (perfect conditions)

$$\text{Match Factor} = \frac{\text{No Trucks} \times (\text{Load} + \text{Spot Time})}{\text{Truck Cycle Time}}$$

$$\text{No Trucks} = \frac{\text{Truck Cycle Time}}{\text{Load} + \text{Spot Time}} = \frac{17.51\ \text{min}}{(3.50 + 1.30\ \text{min})} = 3.65\ \text{Trucks}$$

There are numerous volumes which deal with production and cost estimation. For example, equipment manufacturers such as Terex (1978) and Caterpillar (1981) publish estimating manuals. A number of texts, including those by Church (1981) and Hoskins and Green (1977) also deal with the subject.

Modified Open Pit/Shovel-Truck

Modified open pit or terrace mining is generally used in thick seam properties with low stripping ratios. In these applications, seams are generally flat-lying, gently dipping, or rolling. The method shown in Figure 12 involves opening an initial pit and placing the overburden in temporary off-site storage. Coal is then removed from the initial pit area. The next cut is taken in the direction of mine advance and the overburden is hauled around the existing pit and dumped in the mined-out area. Coal is removed and the haul-back process is repeated as the relatively small pit advances. The "steady-state" overburden situation is indicated in Figure 13.

In new pitching or steeply dipping seam operations, the initial pit would be opened and coal removed. The initial box cut would be opened to the economic limit down dip. Subsequent cuts would be advanced on-strike and overburden hauled back into the mined-out initial pit (Fig. 14).

From a regulatory standpoint, backfilling must be done on an approved schedule with lowest practical grades less 1.3V to 1H. Highwalls must be graded to a maximum of 1V to 2H. Other regulations, regarding topsoil, etc., are similar to those previously discussed.

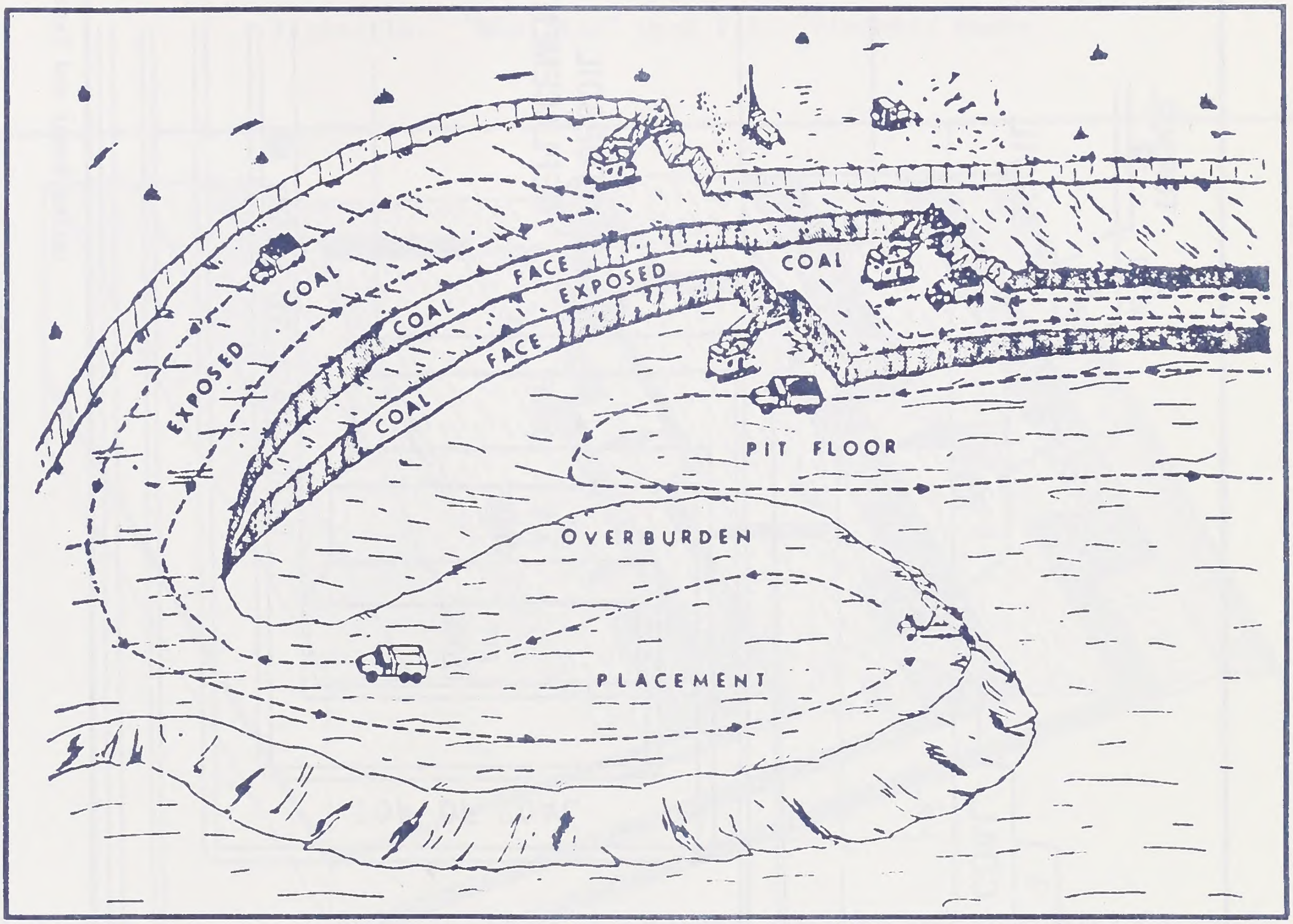
Advantages and Disadvantages

The major advantages and disadvantages of modified open pit/shovel-truck operations are as follows:

Advantages

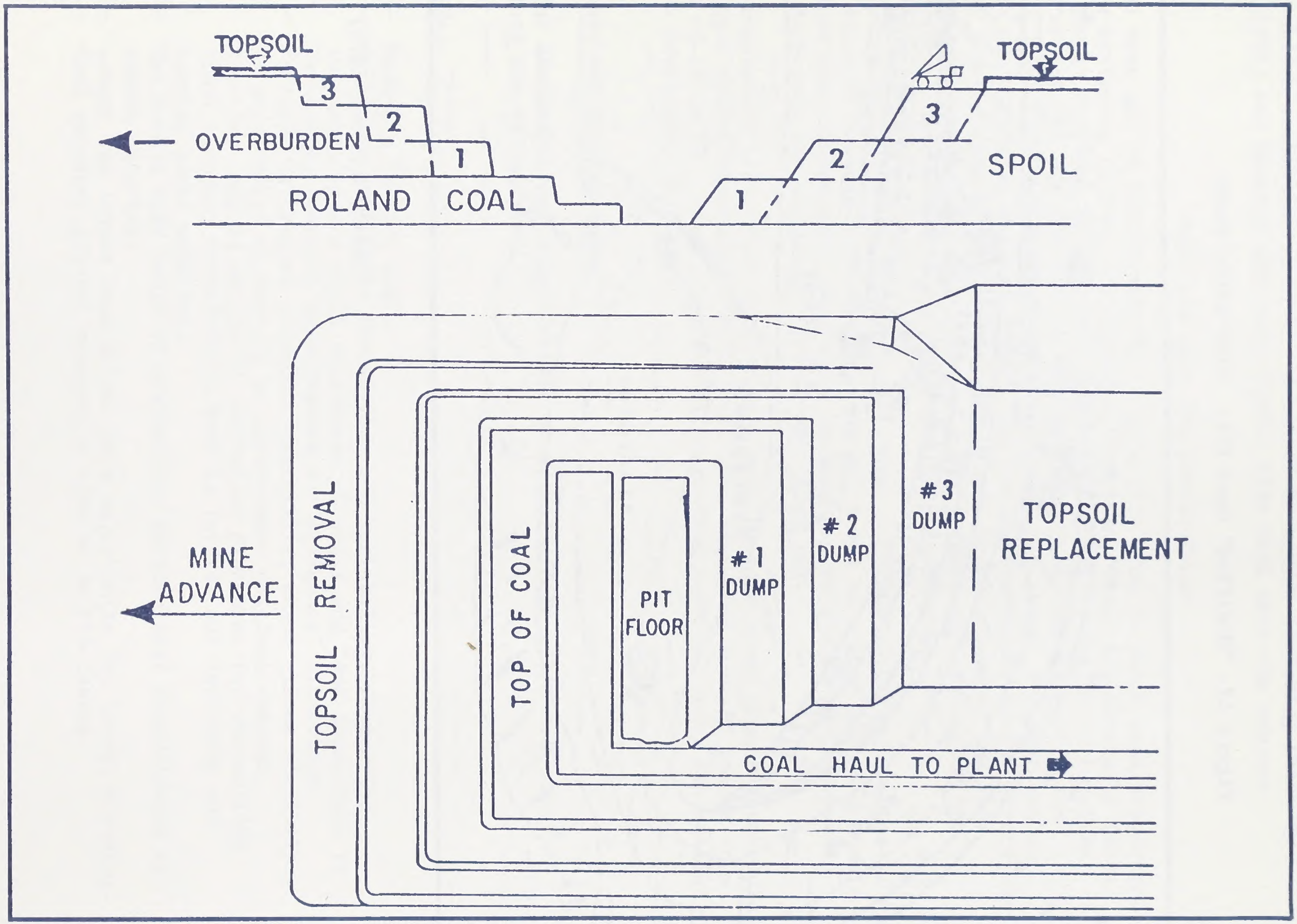
- Moderate capital cost.
- Excellent production flexibility and variability; production increments are a small percentage of total and lend themselves to increasing contract requirements or "diligence" situations.
- Variable horizontal transport capability, which allows flexibility in requirement to restore to approximate original contour.
- Relative ease in obtaining controlled placement for controlling final surface, transferring beds in layers, and isolating and burying toxic material.
- Can handle wide range of overburden, particularly consolidated or coarse material.
- Larger and longer face allows more opportunity for in-pit blending.
- Coal recovery greater because of less or no rib losses.

Figure 12. "Modified" Open Pit: Flat-lying Seams



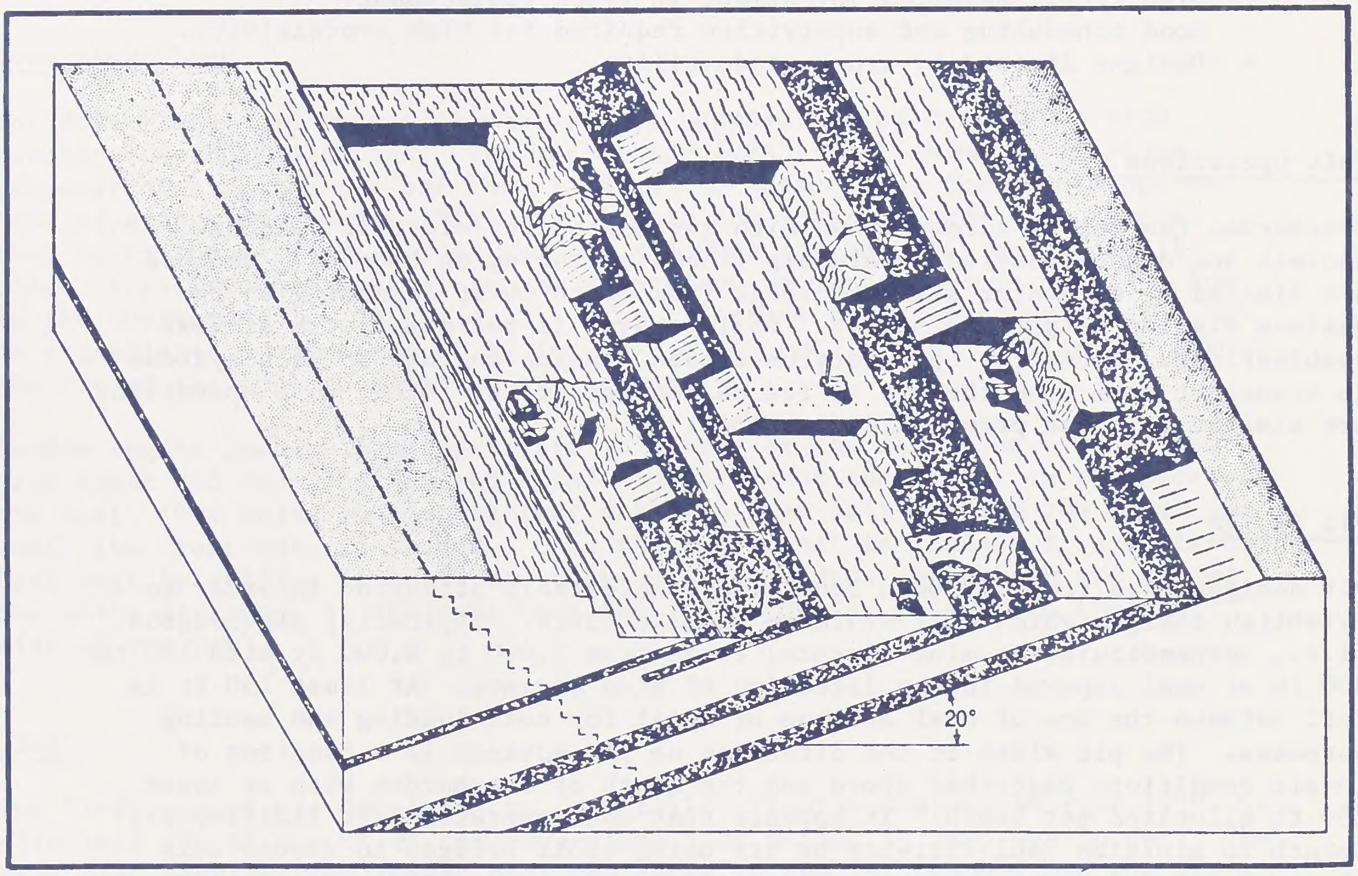
(Skelly and Loy 1975)

Figure 13. Plan and Section of "Modified" Open Pit Overburden Operation.



(After Evans and Tate 1975)

Figure 14. "Modified" Open Pit: Pitching Seams



(After Jackson 1979)

Disadvantages

- Moderate to high operating costs with costs a function of depth and haul distance.
- Labor-intensive.
- Auxiliary equipment required for road maintenance, shovel clean-up, and dust laying.
- Operating costs are a function of equipment and road maintenance.
- Operating costs are closely tied to diesel fuel cost and availability.
- Significant deferred investment in truck replacement.
- Good scheduling and supervision required for high productivity.
- Designs limited by truck gradeability.

Unit Operations

Overburden removal is accomplished with large-capacity electric loading shovels and diesel-powered, rear-dump trucks operating on benches. Benches are limited by excavator size and range from 40 to 60 ft depending on the maximum digging height capability. Coal removal is performed with similar combinations. Recently, operators have been considering use of belt systems to transport coal from the pit to reduce haulage costs. Other unit operations are similar to those previously described.

Pit Design

Pit designs have recently been receiving considerable attention in order to establish designs which will minimize haulage costs. Typically, pit lengths (i.e., perpendicular to mine advance) range from 2,000 to 8,000 ft with 150 to 300 ft of coal exposed in the direction of mine advance. At least 150 ft is left between the toe of coal and toe of spoil for coal loading and hauling purposes. The pit width in the direction of pit advance is a function of in-pit conditions described above and the depth of overburden with at least 150 ft allocated per bench. It appears that most operators are limiting pit length to minimize haul distance or are using spoil bridges to reduce this distance. Some operators are considering vee-shape overburden fronts as opposed to the conventional flat front to take advantage of simple geometry to limit haul distance. Such design modifications will fine-tune the operation and reduce haulage costs.

Block Area/Dozer-Scraper

The block area method, which utilizes construction-type equipment, was first conceived in the mid-seventies as an alternative to area/dragline methods. At that time, draglines were not readily available because of the high demand and long lead times in procurement. Alternative methods were sought which would employ readily available construction-type equipment (i.e., dozers and scrapers). Designs evolved into methods utilizing a combination of dozers and scrapers including down-slope load, "Z-2," and horizontal load. All of these methods take advantage of the dozer's ability to move material over short distances at low costs and the scraper's ability to elevate material over steep grades for short distances at reasonable costs.

In all three of the methods, it must be noted that there is a relatively narrow window of application from a material standpoint. As degree of consolidation of material increases, wear and tear on the scrapers makes the methods cost-prohibitive because of high repair, maintenance and supply costs, and reduced machine productivity.

Down-slope Load

The down-slope load method is employed in unconsolidated overburden with moderate overburden depths. The method involves establishing a 15% slope perpendicular to the pit and then loading the scrapers on the down slope to take advantage of gravity (Fig. 15). After the scrapers have been loaded, they carry the material across the pit and dump the material on the spoil side. Stratigraphic control can be maintained by dumping loads obtained low in the overburden low in the spoil. The 15% grade on the overburden side can be established by scrapers or by dozers. A key cut is then utilized to expose the rib of the coal to minimize rib losses.

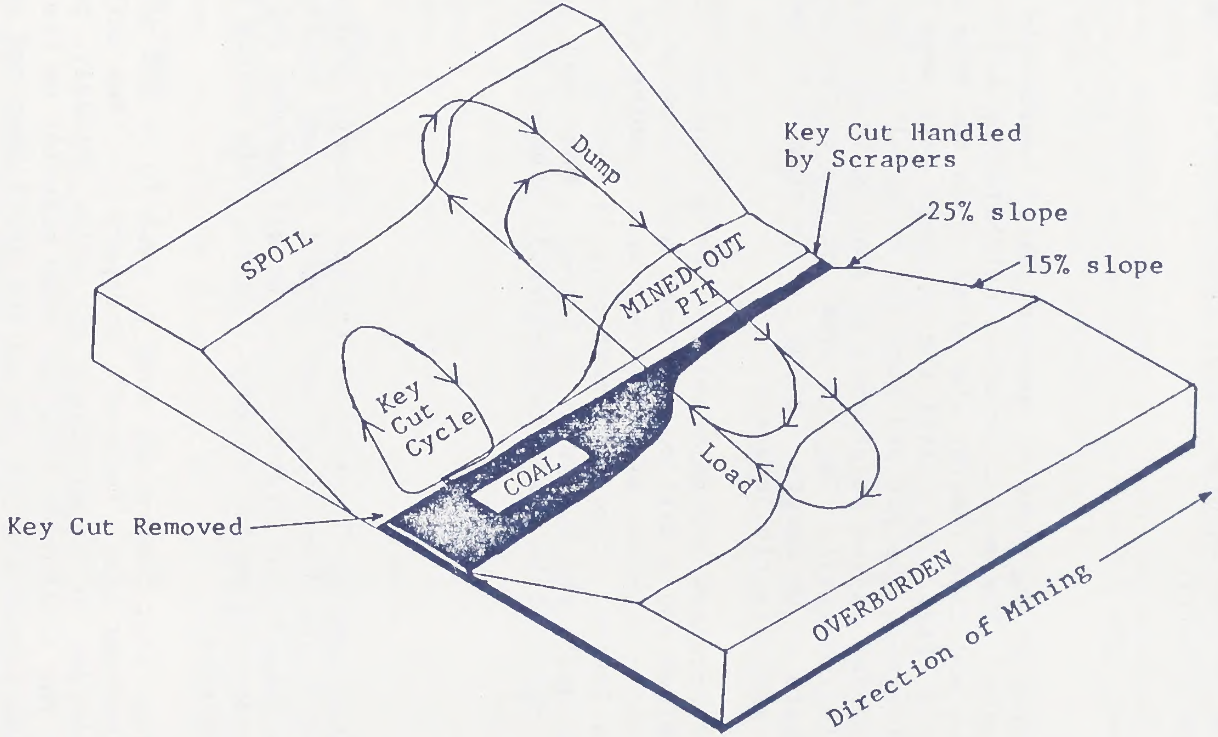
Tandem engine push-pull scrapers are selected for the stripping. These units have front and rear engines and a bail on the front and a hook on the back of the unit. Two units couple together with the rear unit pushing the front unit until the front unit is loaded. Once the front unit is loaded, it assists the back unit by pulling it until the back unit is loaded. Once both are loaded, the units disengage at the bail/hook and independently proceed to the spoil side of the pit.

"Z-2"

The "Z-2" method was developed by Caterpillar Tractor Company (Morgan 1979) to alleviate the high cost of the down-slope load method in deep overburden. The high cost results from longer haul distances as the pit deepens and the slope distance in the overburden and spoil increase. Again, this method is utilized in unconsolidated overburden.

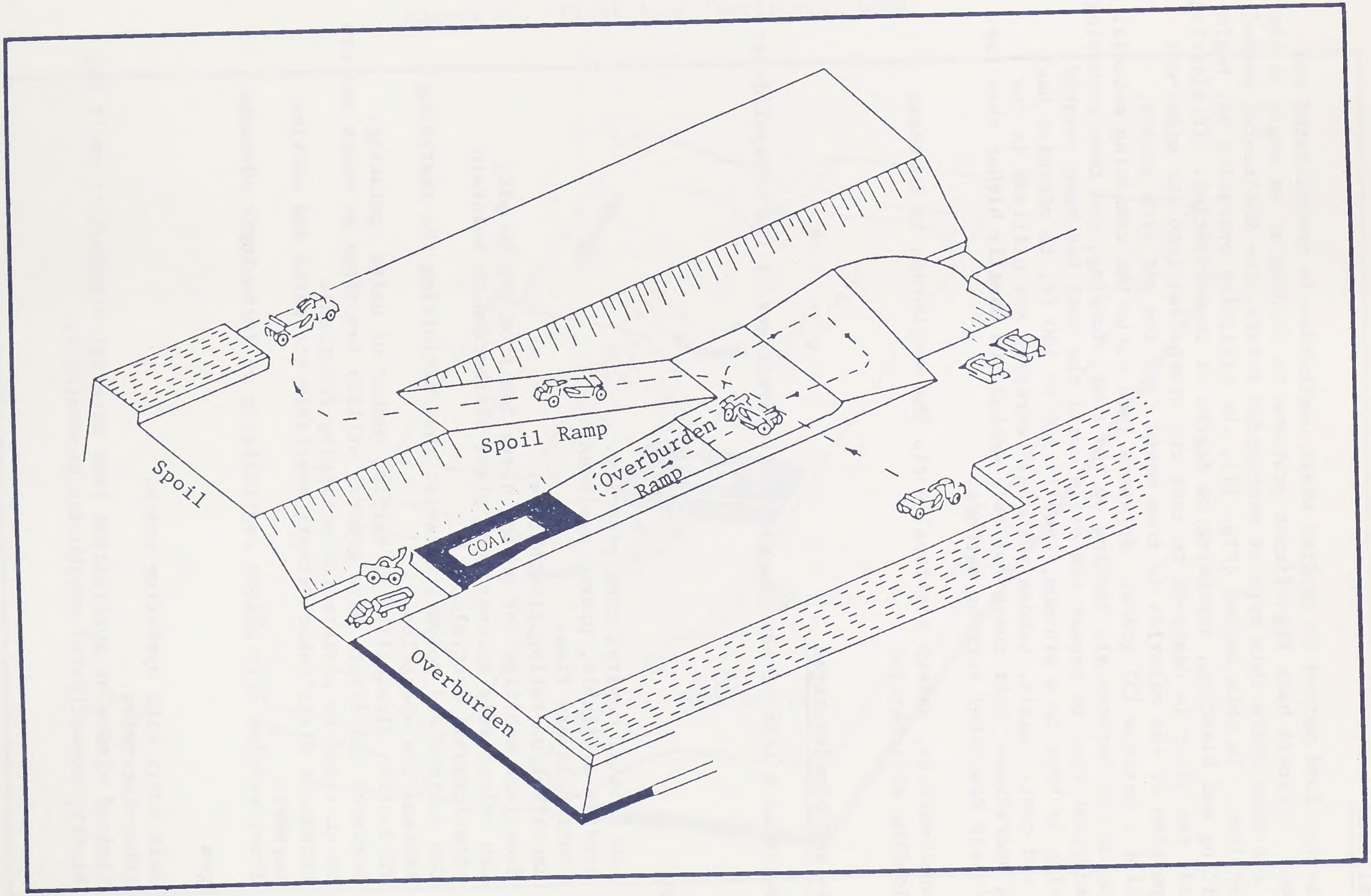
In the "Z-2" method (Fig. 16), dozers are used to push 20 to 30% of the overburden into the mined-out pit. Push-pull scrapers are then utilized to remove the middle-overburden to the mined-out pit area. Finally, push-pull scrapers are loaded on the overburden ramp and dump material on the spoil ramp. Topsoil is hauled across the pit and up the spoil ramp and can be directly redistributed. Coal must also be hauled up the overburden and spoil ramps out of the pit. One of the major problems perceived with this proposed method is the congestion on the ramps and the difficulty of maintaining stable haul roads during spoil loading and dumping. However, theoretical economies with the system (Ryan 1982) may outweigh these problems.

Figure 15. Block Area/Down-Slope Load.



(After Ryan 1982)

Figure 16. Block Area/"Z-2"



(After Ryan 1982)

Horizontal Load

The horizontal load method is applied where overburden is consolidated and stratified. Scrapers have significant problems in loading at an angle to the bedding, and thus where this type of overburden exists, the horizontal method must be applied. In this method (Fig. 17), the stripping operation may begin with drilling and blasting, depending on degree of consolidation. If blasting is applied, the blast is designed to cast the overburden into the mined-out pit. A portion of the material is then moved into the pit with dozers, establishing a maximum 15% grade. Scrapers then strip the remaining material by loading on the horizontal, hauling up the ramp, dumping, and then returning down an adjacent ramp to repeat the cycle until the coal has been reached. Ramp spacing is kept to a minimum, usually 300 to 500 ft, to minimize haul distance and cost. Again, tandem push-pull scrapers are utilized in the stripping operation. Unit costs for this method are usually higher than for the previously described scraper methods.

In all three methods, dozers continually rip the overburden to increase scraper loading efficiency.

Advantages and Disadvantages

The following is a list of advantages and disadvantages of the scraper/dozer systems.

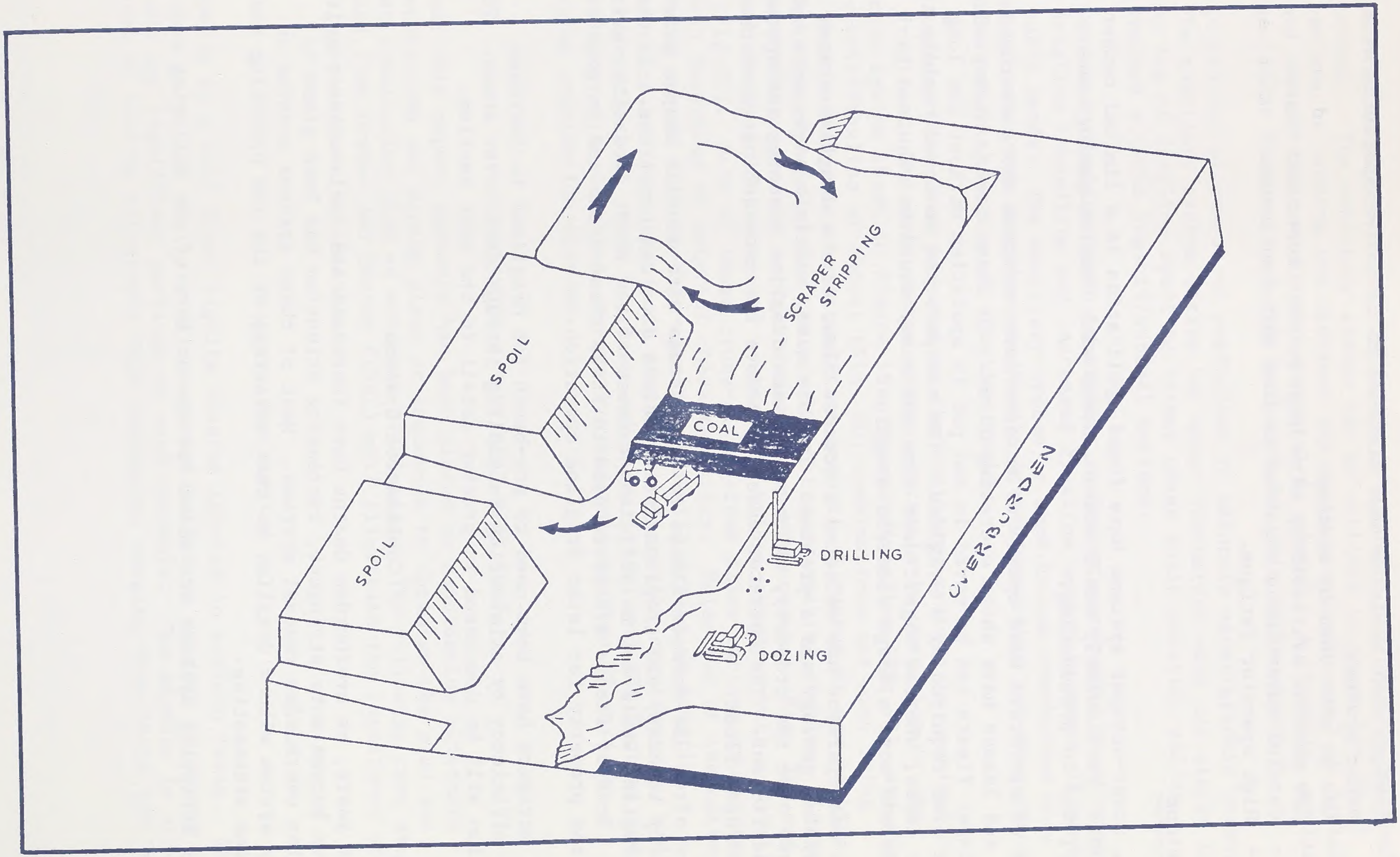
Advantages

- Low initial capital cost/capacity.
- Readily available, proven equipment.
- Short delivery time.
- Excellent operating flexibility.
- Excellent mobility for moving operation from pit to pit.
- Can selectively excavate and place overburden to maintain stratigraphic control.
- Can contour and compact material thus minimizing the regrading reclamation operation.
- Production flexibility by varying number of units operating.
- Scrapers and dozers have general utility functions at mines and can be utilized to perform non-stripping functions.
- Extensive distributor network available for parts and service support.
- Short service life allows capitalizing on technologic advances.

Disadvantages

- Relatively high operating costs.
- Labor-intensive.
- Limited window of application from material standpoint; can't dig blocky, consolidated overburden economically.

Figure 17. Block Area /Horizontal Load



(After Ryan 1982)

- Designs must minimize haul distance to be cost-competitive with other systems.
- Can be shut down by weather.
- Low machine availability with high percent scheduled hours.
- Careful supervision required in load and dump areas.
- High operator fatigue.

Applications

To date, dozer-scraper systems have found application in a limited number of situations: particularly small leases, areas with complex geology and geometry, and in prebenching.

A number of operators have opted for scraper/dozer systems where overburden permits and leases have short operating lives. In these cases, high-production scraper fleets can be moved in and put in operation without the long erection time required by a dragline. The scrapers can be moved rapidly to the next lease, whereas significant time and money would be required to dismantle and move a large electric dragline.

At least one operator has selected a scraper fleet over a dragline system where complex geology was a problem. In this case, multiple seams were not continuous over the property, which would make dragline planning and operation quite inefficient. The operator chose to remove the unconsolidated overburden with a scraper fleet.

Operators often use scraper fleets to strip areas with unusual shapes existing at property boundary and cropline intersections or along croplines. In these cases, dragline would not be efficient because of the short pits with variable lengths. Scraper fleets are often used to strip these areas and in some cases prepare the property for later dragline operation.

Finally, scrapers have been used to pre-bench for draglines to increase dragline efficiency by eliminating rehandling through deep cover areas. This application will be discussed in greater detail in the next section.

Combination Systems

In recent years, as overburden depths have increased and reclamation requirements have become more stringent, increasing attention has been given to combination overburden removal systems. Most of these systems combine an auxiliary system with a dragline to take advantage of the low operating cost of dragline sidecasting.

Auxiliary stripping systems are added for one or more of the following reasons:

1. Controlled placement of overburden to maintain approximate original contour. The auxiliary system can be utilized to shape the final surface by varying the distance the upper overburden zone is hauled and the location where this material is placed. A flexible, mobile equipment system is usually selected for this application.

2. Controlled placement of overburden to maintain stratigraphic control. The auxiliary system strips the upper overburden zone and places it on top of dragline spoil to either cover toxic material and/or replace a thick topsoil/subsoil horizon.

3. Extended dragline depth capability in deeper overburden to eliminate dragline rehandling and increased dragline output in terms of bank cubic yards. The auxiliary system is used to cut overburden to a depth that the dragline can handle with sidecasting and then place the material on top of dragline spoil.

Numerous systems have been proposed as the auxiliary systems in combination with the dragline. The most common system currently in operation is the shovel/truck system shown in Figure 18. Scraper/dragline (Fig.19), and wheel excavator-belt/dragline or shovel (Fig. 20) combinations are also being utilized where overburden characteristics permit. A number of new machine designs have been proposed for the pre-bench transportation problem. Learmont and Chare (1980) suggested a cantilevered cross-pit conveyor (Fig. 21) and SNC Tottrup and Krupp (1980) proposed a cross-pit bridge conveyor with a rotating stacker (Fig.22). Both of these cross-pit systems allow various excavators to be utilized depending on material characteristics. Selection of the optimum pre-benching system will be site-specific and will depend on material characteristics and quantity, haul distance, reclamation requirements, and comparative economics. Both Learmont and Chare (1980) and SNC Tottrup and Krupp (1980) provide detailed comparative economic studies of various pre-benching combination systems.

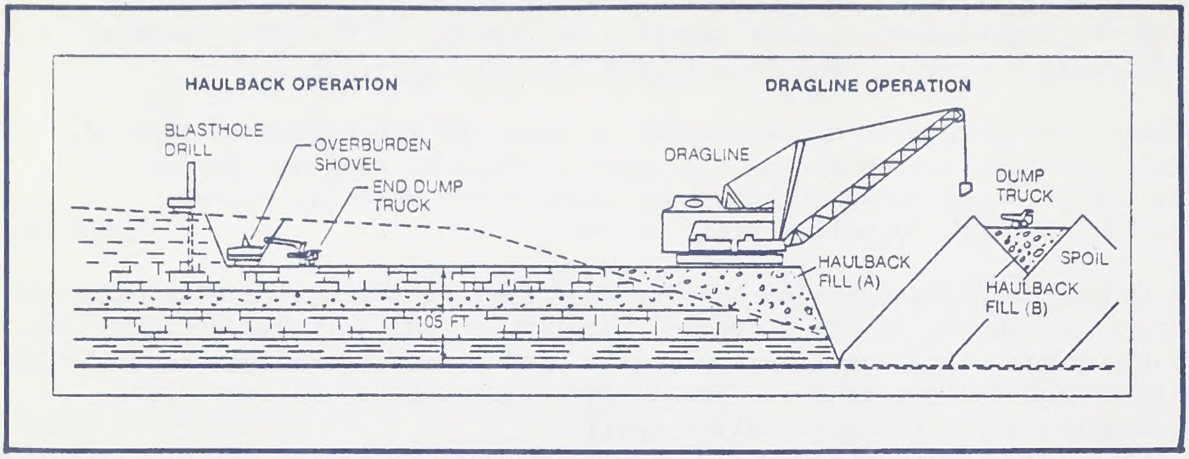
CASE STUDY - "OPTIMUM" MINE PLAN

Throughout this paper, emphasis has been placed on considering alternate equipment systems and mining plans or sequences to optimize the plan and equipment combination from an economic standpoint. The following case study summarized from Hrebar and Sherer (1981) will illustrate the importance of considering various alternatives.

Property Description

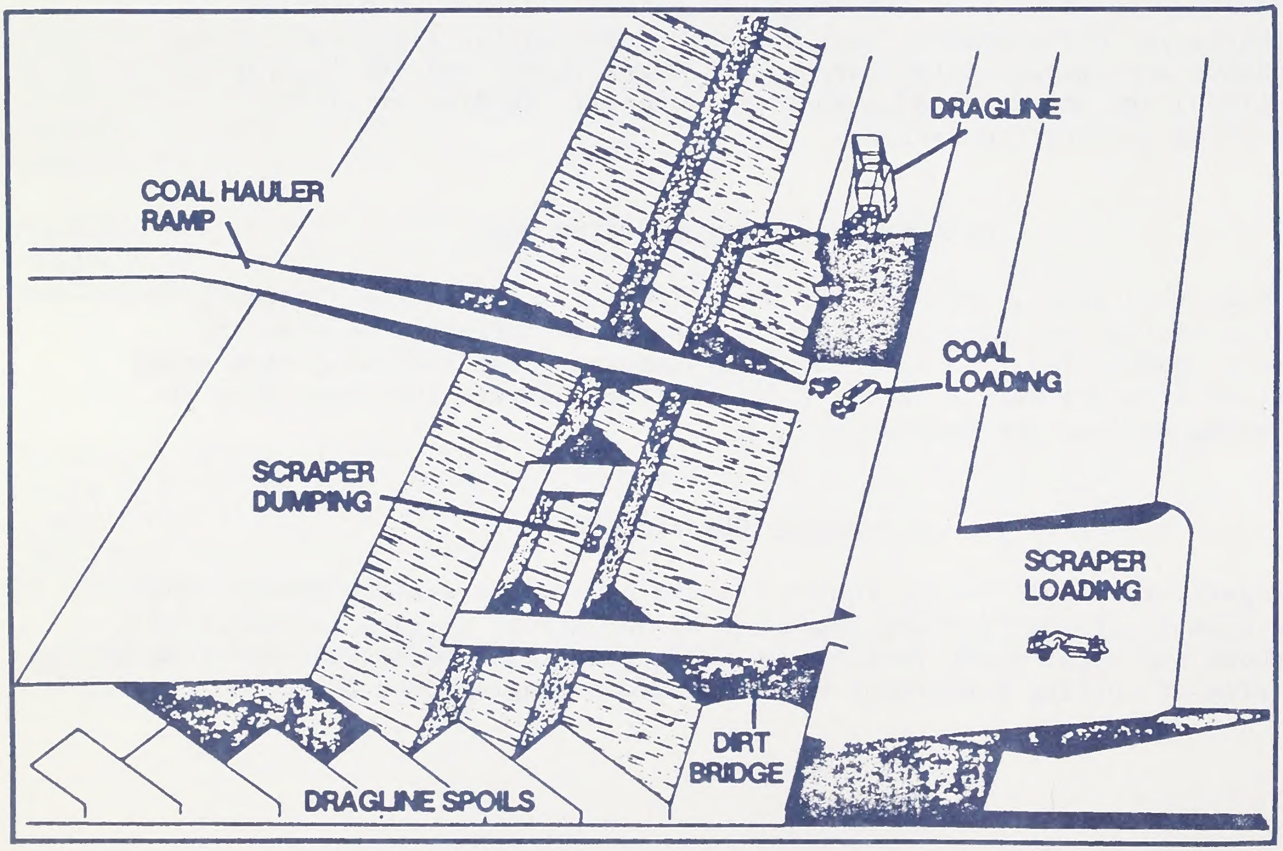
The property is a Gulf Coast lignite reserve located in eastern Texas. The single seam is of the Tertiary Wilcox group and has an average thickness of 5 ft without any significant partings or sand channels. The deposit is situated in an area of rolling topography with overburden ranging from 20 to 160 ft.

Figure 18. Combination System: Shovel-Truck/Dragline.



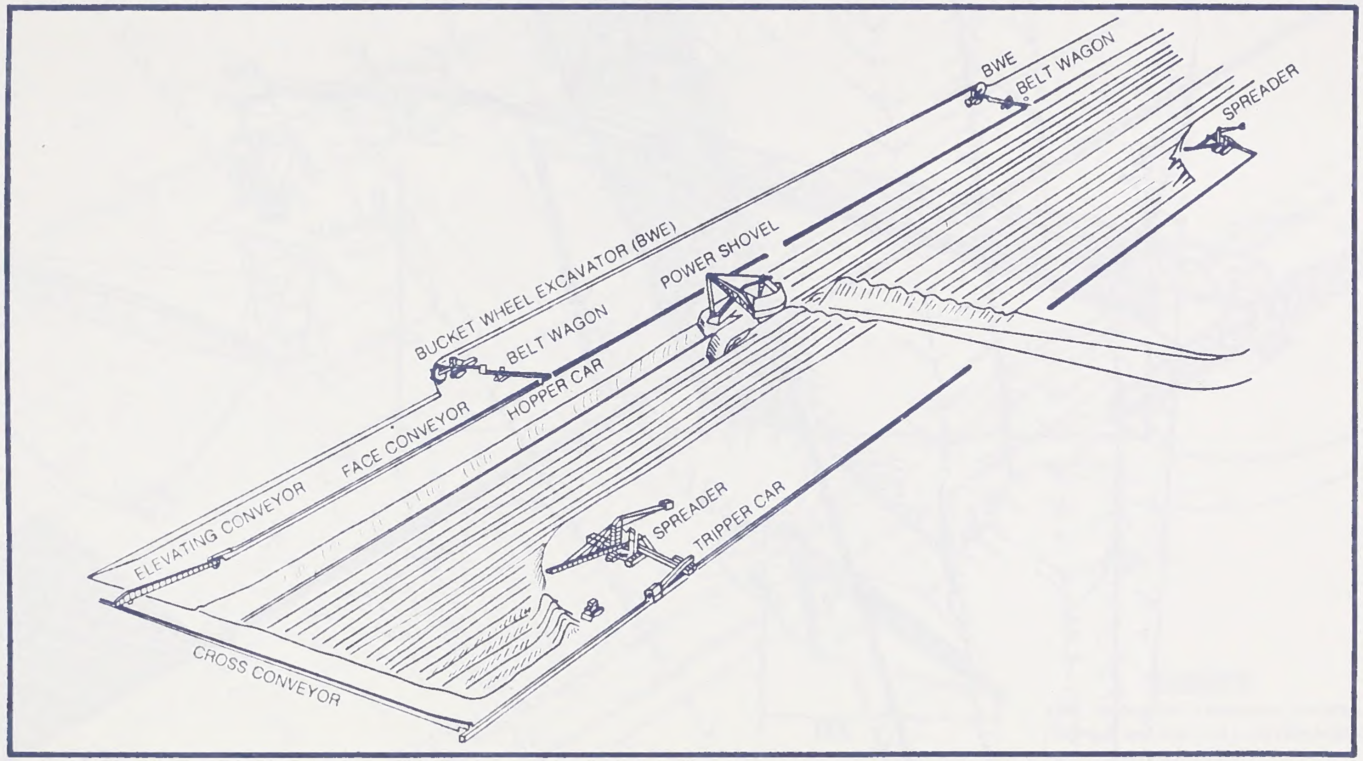
(Chironis 1980a)

Figure 19. Combination Systems: Scraper/Dragline.



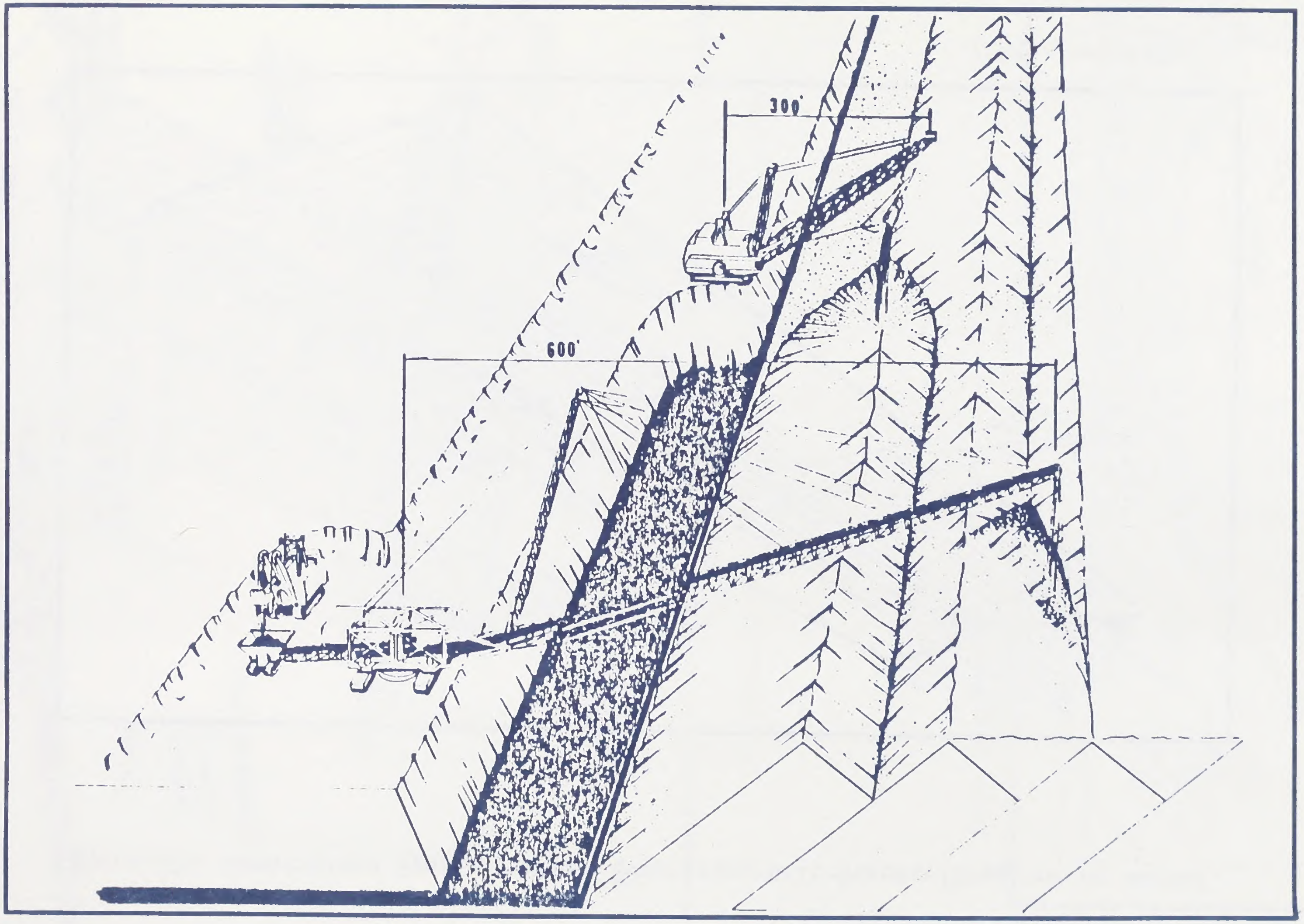
(After Morgan and Williams 1980)

Figure 20. Combination System: Wheel Excavation-Belt-Stacker/Dragline or Shovel.



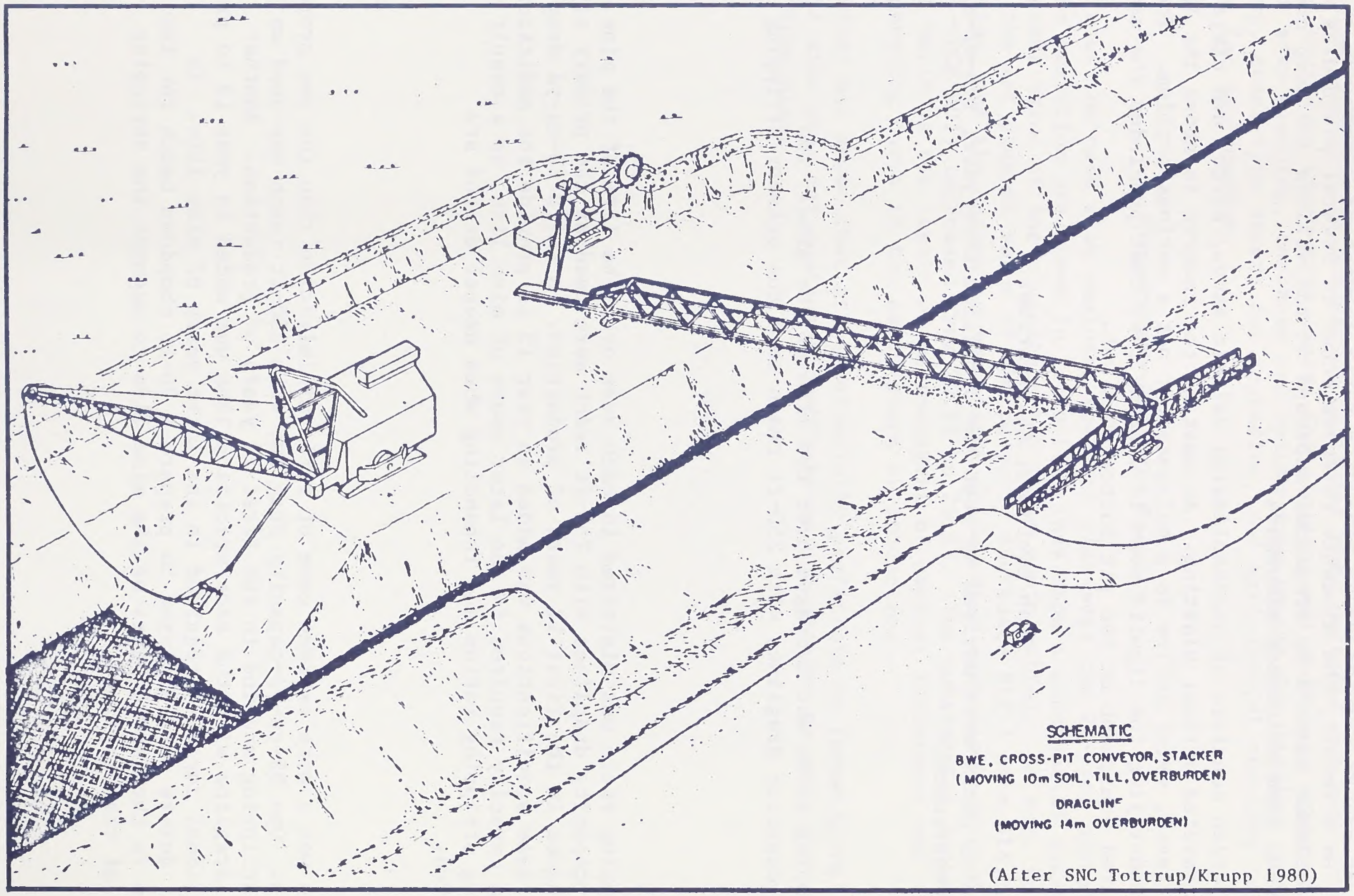
(Chironis 1980b)

Figure 21. Combination Systems: Loading Shovel-Hopper-Cross-Pit Conveyor/Dragline.



(After Learmont and Chare 1980)

Figure 22. Combination System: Wheel Excavator-Bridge Conveyor-Rotating Stacker/Dragline.


SCHEMATIC
BWE, CROSS-PIT CONVEYOR, STACKER
(MOVING 10m SOIL, TILL, OVERBURDEN)
DRAGLINE
(MOVING 14m OVERBURDEN)

(After SNC Tottrup/Krupp 1980)

As a result of varying seam thickness and overburden depth, the stripping ratio varies from less than 5 to over 40 bank cubic yards per ton. The property is cut by several major drainages where lignite is absent due to erosion. As a result, the mineable reserves occur in several peninsulas and isolated islands bounded by erosional subcrops in the valleys and deep cover and thinning seam thickness elsewhere.

The overburden consists of unconsolidated deltaic sands, silts, and clays that may be excavated without blasting. As most of the reserve is above the local drainage level, water inflow is a nuisance but not a serious problem. The stratum underlying the lignite seam is a sandy clay that precludes the use of rubber-tired equipment on the pit bottom when wet.

Plan/Equipment Alternatives

Three mining plans were devised to meet the 3 million tons/year, run-of-mine lignite requirement:

Plan A

The stripping ratio was averaged over the life of the mine. Two 83-cu-yd-capacity draglines with 250-ft reach were the primary stripping machines.

Plan B

The stripping ratio was minimized in each year over the life of the mine. Two 60-cu-yd-capacity draglines with 250-ft reach were used as the primary stripping machines in the first 12 years of production. A third 60-cu-yd dragline with the same specifications was added in year 13 to provide the additional stripping capacity required in the later years of mine life, as a result of increasing stripping ratios and rehandling when deeper depths are encountered.

Plan C

This plan was a more extreme case of ratio minimization than the one proposed in Plan B. One 95-cu-yd-capacity dragline with 250-ft reach was used as the primary stripping machine in the first 12 years of production. Another 95-cu-yd dragline with the same specifications was added in year 13 to provide the additional capacity required in the later years of mine life. In addition, dozers were employed to prepare a 30-ft chopdown bench for the two draglines in the last 4 years of the mine life to augment the stripping capacity of the draglines.

The dragline production summary for each plan, which produced 3 million tons/year run-of-mine, is shown in Table 14.

For each plan, appropriate numbers of equipment were selected for each unit operation, including track-type dozers for clearing and grubbing, rubber-tired dozers for seam cleaning, backhoes and bottom-dump trucks for lignite loading and hauling, track-type dozers for regrading, and agricultural tractors and implements for reclamation.

Comparative Economic Results

The results of the cash flow analyses for each plan over the 24-year operating life of the operation are shown in Table 15. They show a substantial increase in the present value of the property using ratio minimization. As seen in Table 15, the net present value of the property increased $12.1 from $16.6 to $28.7 million, and the return on investment (discounted cash flow-return on investment--DCF-ROI) increased from 20.5% to 28.3%. The substantial increase in present worth is the result of postponement of capital investment and lowered operating costs in the early years of production.

The case study has shown that it is potentially profitable to investigate alternative mine plan and equipment combinations and attempt to seek the "optimum" mine plan.

Table 14. Case Study - Dragline Production Summary

	Plan A				Plan B				Plan C			
Production Years	Stripping Ratio (BCY/T)	Required Bucket Capacity (CY)	Number of Draglines	Number* of Shifts	Stripping Ratio (BCY/T)	Required Bucket Capacity (CY)	Number of Draglines	Number* of Shifts	Stripping Ratio (BCY/T)	Required Bucket Capacity (CY)	Number of Draglines	Number* of Shifts
1-3	13.0	145	2	5.25	11.2	105	2	6	9.6	89	1	3
4-6	13.0	145	2	5.25	10.9	103	2	6	8.3	78	1	3
6-9	13.0	145	2	5.25	9.8	91	2	6	10.3	96	1	3
10-12	13.0	145	2	5.25	11.0	107	2	6	10.3	97	1	3
13-15	13.0	145	2	5.25	13.3	154	3	8	14.2	149	2	5
16-18	13.0	145	2	5.25	13.8	152	3	8	15.4	150	2	5
19-21	13.0	145	2	5.25	15.0	169	3	9	15.8	172	2	6
22-24	13.0	145	2	5.25	18.0	178	3	9	17.4	203	2+	6+

* No. of dragline shifts worked per day for a 5 day work week.

Table 15. Case Study-Economic Summary

Mine Plan	A	B	C
Initial Investment ($1,000)	108,236	82,341	73,710
Deferred Investment ($1,000)	52,131	71,684	89,873
Total Investment ($1,000)	160,367	154,025	163,583
Operating Costs:			
First Production Yr. ($/ton lignite)	7.72	7.32	6.77
Last Production Yr. ($/ton lignite)	7.91	8.61	8.77
Net Present Value at 15% ($1,000)	16,631	24,794	28,739
Discounted Benefit Cost Ratio @ 15%	1.35	1.70	1.90
Internal Rate of Return (DCF-ROI)	20.5%	25.4%	28.3%

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BLM AIR QUALITY HANDBOOK
FOR SURFACE COAL MINES

by

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Environmental and Hydrological Services
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Boise, Idaho 83729

LIST OF ACRONYMS

ANFO - Ammonium Nitrate Fuel Oil

BACT - Best Available Control Technology

CDM - Climatological Dispersion Model (EPA)

DEQ - Department of Environmental Quality (Wyoming)

DH - Department of Health (Colorado)

DHES - Department of Health and Envrionmental Science (Montana)

EIS - Environmental Impact Statement

EPA - Environmental Protection Agency (US)

ERTAQ - Environmental Research and Technology Air Quality (computer model)

NAAQS - National Ambient Air Quality Standards

NEPA - National Environmental Policy Act of 1969

NOI - Notice of Intent

NSPS - New Source Performance Standards

OSM - Office of Surface Mining

PSD - Prevention of Significant Deterioration

SIP - State Implementation Plan

SMCRA - Surface Mining Control and Reclamation Act of 1977

TSP - Total Suspended Particulates

INTRODUCTION

Federal and State air quality regulations, which have been formulated during the last 15 years, are being used to regulate the siting and operation of industrial facilities in an effort to balance economic development with good industrial hygiene and environmental preservation. Planned industrial operations which would potentially emit particulate or gaseous materials into the atmosphere require an analysis of their emissions and related consequences, as well as a plan to mitigate the effects of such emissions. The mining industry is regulated under such laws at both the State and Federal level. This document presents a discussion of air quality impacts, analysis techniques, and mitigation strategies for surface coal mines in the Western United States, specifically those in Colorado, Montana, North Dakota, and Wyoming.

Of primary importance in evaluating air quality in relation to surface mining is the fact that both impacts and mitigation measures are highly individualized and vary considerable from project to project. Differing mine design characteristics, regulations, meteorology, terrain, and pre-existing air quality all contribute to this individuality. Therefore, the guidelines presented herein outline the basis for analysis but require modification to fit a specific mining operation. As an information document delineating air quality issues associated with surface mining activities, this cannot substitute for a competent air quality consultant or for a well-informed mine engineering staff.

The objective of this document is to facilitate an understanding of air quality considerations in general as well as to provide a working knowledge which can be applied to specific coal mining projects. It summarizes the steps required in conducting an air quality impact analysis for a surface coal mine, outlines the options currently available for completing each step, and quantifies the relative advantages of each option, where possible. Emphasis is placed on utilizing of appropriate particulate emission factors, air quality computer models, and emission mitigation strategies to assess air quality impacts of mining activities.

Some of the major concerns likely to be encountered in planning for operating a mine are highlighted and the various required analyses are related to government regulations and operational considerations. Impacts in terms of emissions factors, mathematical models, and control strategies are discussed and summarized for reference on comparative tables.

The second section summarizes the air quality regulatory requirements applicable to surface coal mines and their role in permitting construction and operation. The third section, a brief overview of the surface mining process, describes the dust-producing mining operations and their relationship to the mine design and various technical evaluations.

A comprehensive summary of currently available emission factors used to quantify dust emissions from mining activities is presented in the fourth section. The method of their derivation, their application to specific mine dust sources, and State by State agency preferences are also discussed. The fifth secton discusses emissions from three typical surface coal mines as an illustration in the application of emission factors. Dragline, scraper, and truck/shovel mine types are separately evaluated. Emissions from each source at each of these three mine types are presented on a normalized basis, comparisons between emissions from the three mine types are made, and source contributions are ranked.

The sixth section describes the considerations necessary to accurately conduct an air quality impact analysis for a surface coal mine. Characteristics, assumptions, and limitations of available computer models are summarized. The importance of adequate baseline meteorological and air quality monitoring data is demonstrated. Normalized ambient concentrations resulting from operating surface mines are discussed using an example from a specific operating mine.

The seventh section consists of a comprehensive summary of mitigation measures commonly used to control particulate emissions. This section is a key discussion because the chosen mitigation strategies have significant economic and operational consequences. Many of these strategies are fixed requirements specified by regulatory agencies. The section lists agency-preferred control strategies and the effectiveness ascribed to them, with the objective of promoting a mine design which is economical, efficient, and well controlled in terms of atmospheric emissions.

REGULATORY CONSIDERATIONS

Surface coal mines are regulated by a variety of Federal, State, and local agencies. A typical surface mine may acquire and maintain 40 to 60 separate permits before operations begin. These range from a major Federal environmental impact statement (EIS), water and air quality reviews, and detailed State mining permits to local building permits and utility easements. Although several of these permits include oblique references to climatological data or existing air quality, this chapter discusses only matters relating to air quality permitting of surface coal mines under Federal and State air quality regulations.

Federal and State air quality regulations generally embody requirements for a "permit to construct" whereby certain analyses must be performed before the planned facility is approved for development. After the facility is built, State regulations often require a separate "permit to operate" which stipulates the operating conditions and is renewed from time to time. Both types of permits contain provisions for compliance inspections by the agency and for civil or criminal penalties for unresolved violations.

FEDERAL LEGISLATION AND REGULATION

The Clean Air Act

The first Clean Air Act passed in 1963, contained the first Federal air pollution regulatory authority empowering the Federal government to intervene in interstate air pollution problems that could not be solved by the states involved. Specifically, under certain conditions the Federal government could initiate procedures to secure abatement of the pollution by convening a public abatement conference, which would provide information for developing rational recommendations for pollution abatement at the source.

The Clean Air Act was subsequently amended in 1965, 1966, 1967, 1970, 1974, 1977, and 1980. In 1965, the Act was amended by the addition of the Motor Vehicle Air Pollution Control Act which authorized Federal emission standards for new vehicles. The 1967 amendments considerably broadened Federal regulatory functions by giving the Federal government authority to adopt emission control regulations in designated areas which had air pollution problems and also provided a system of limited enforcement.

1970 Amendments

In 1970, the full scope of the air pollution problem was recognized on a national scale along with the ineffectiveness of earlier legislation. Consequently, the 1970 amendments to the Clean Air Act greatly expanded the Federal role in air pollution control. Administration of the act was transferred from the Secretary of the Department of Health, Education, and Welfare to the Administrator of the newly formed Environmental Protection Agency (EPA).

Under the Clean Air Act of 1970, the EPA has established National Ambient Air Quality Standards (NAAQS) for those pollutants which are determined to have adverse effects on public health and welfare. As legal limits placed on ambient levels of air pollution during a given period of time, air quality standards characterize the allowable level of a pollutant or a class of pollutants in the atmosphere and, thus, define the amount of exposure deemed safe for the population or ecological systems. Table 1 presents the primary and secondary National Ambient Air Quality Standards. The primary standards reflect levels of air quality, including an adequate safety margin, necessary to protect public health. Each State must attain the primary standards no later than December 31, 1982. The secondary standards reflect the levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. Both primary and secondary NAAQS apply everywhere, even on private property.

State Implementation Plans (SIP), also required by the 1970 act, provide a structure under which State and local governments are expected to set up the regulatory framework necessary to achieve the NAAQS in their jurisdictions. The SIP requirement helps to fulfill the Congressional philosophy that "the prevention and control of air pollution at its source is the primary responsibility of State and local governments" (Clean Air Act, 1970, Section 101 (2) (3)). Through this process the states become major partners with the Federal government in the control of air pollution. The SIP's for Wyoming, Montana, North Dakota, and Colorado are discussed under the State Implementation section.

In addition to setting the NAAQS and SIP requirements, the Clean Air Act of 1970 also charged the newly formed EPA with establishing New Source Performance Standards (NSPS) for stationary sources and hazardous pollutants and emission standards for motor vehicles.

1977 Ammendments

In 1977, Congress amended the Clean Air Act to affirm as national policy the Prevention of Significant Deterioration (PSD) in those areas where the ambient air quality standards are already being met. The determination of what level of degradation is "significant" is dependent on local conditions. Three types of areas are defined in the Act:

TABLE 1. NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	National Standards[a] Primary	Secondary
Oxidant (ozone)[c]	1 hour[b]	235 $\mu g/m^3$	d
Carbon monoxide	8 hour[b]	10 mg/m^3	d
	1 hour	40 mg/m^3	d
Nitrogen dioxide	Annual	100 $\mu g/m^3$	d
Sulfur dioxide	Annual	80 $\mu g/m^3$	-
	24 hour[b]	365 $\mu g/m^3$	-
	3 hour[b]	-	1300 $\mu g/m^3$
Suspended particulate matter	Annual (geometric mean)	75 $\mu g/m^3$	60 $\mu g/m^3$
	24 hour	260 $\mu g/m^3$	150 $\mu g/m^3$
Lead	Calendar quarter	1.5 $\mu g/m^3$	d
Hydrocarbons	3 hour[b] (6-9 AM)	160 $\mu g/m^3$	d

---

[a] National standards, other than that for ozone or those based on annual averages, are not to be exceeded more than once per year. The national ozone standard is not to be exceeded more than once per year based on a 3-year running average.

[b] Not to be exceeded more than once per year.

[c] National standards specify ozone.

[d] Same as primary standard.

Class I - Applies to "pristine" regions of special environmental concern such as national parks and wilderness areas for which almost any change in air quality would be considered significant. In addition, Indian reservations may be designated as Class I areas.

Class II - Applies to areas where air quality changes accompanying moderate, well-controlled growth would be permitted. The majority of land meeting the NAAQS is designated as Class II areas.

Class III - Applies to areas where maximum growth would be permitted and air quality levels would be allowed to approach the secondary NAAQS.

Allowable PSD increases in ambient concentrations for each area type, as defined in the 1977 amendments, are presented in Table 2. The only pollutants presently covered are sulfur dioxide and particulate matter. Concentrations of these pollutants in any attainment area cannot increase by more than the designated amount while remaining below the NAAQS.

Because the allowable concentration increments in the Class I and Class II areas are so small, it became important for a prospective emission source to determine whether it was subject to the provisions of the Federal Clean Air Act PSD provisions.

The PSD requirements apply directly to 28 designated categories of industrial facilities with the potential to emit 100 tons per year (tpy) of any regulated pollutant and to any industrial source with the potential to emit 250-tpy of any pollutant. Surface mines are a 250-tpy source. PSD sources must apply Best Available Control Technology (BACT), which is determined by the agency on a case-by-case basis and applies to all pollutants covered by the act.

Briefly, surface coal mines become subject to the Federal PSD program if emissions of any pollutant which emanate from stacks, vents, ducts, or other definable exits ("point source emissions") exceed 250 tpy after the application of controls. Fugitive emissions are not included in determining the 250-tpy threshold. Using this criteria, many surface mines are not subject to PSD because they can adequately control emissions. In some cases, however, the mine is located near a thermal coal dryer or a power plant. In such cases, emissions from the dryer or boiler stack exceeding 100 tpy after controls make the dryer or boiler a PSD source, and, since the mine is an integral part of the facility, it becomes subject to PSD requirements as well.

Supplementary Federal Legistation

The Clean Air Act and its subsequent amendments are the primary Federal legislation dealing with control of air pollution. However, there are two other laws dealing with total environmental issues of which air quality is one part. The first of these is the National Environmental Policy Act of 1969 (NEPA). NEPA declares the national environmental policy to be the use by the Federal government of "all practicable means and measures, including financial and technical assistance, in a manner calculated to foster and promote the general welfare, to create and maintain conditions under which man and nature can exist in produc-

TABLE 2. PSD INCREMENTS

Pollutant	Averaging Time	Increments (μg/m³)		
		Class I	Class II	Class III
Sulfur dioxide	Annual average	2	20	40
	24-hour	5	91	182
	3-hour	25	512	700
Particulate matter	Annual average	5	19	37
	24-hour	10	37	75

tive harmony, and fulfill the social, economic, and other requirements of present and future generations of Americans." (NEPA 1969, Title 1 Section 101 (a)).

In order to fulfill this policy and meet national environmental goals, NEPA set forth the environmental impact statement (EIS) as the method to accomplish this. NEPA requires a detailed EIS for any major action which affects environmental quality and which is supported by Federal funds or involves Federally owned or managed land. The EIS must include a detailed review of the following:

> The environmental impact of the proposed action,
>
> Any adverse environmental effects which cannot be avoided should the proposal be implemented,
>
> The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
>
> Any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

EISs are reviewed by State and local agencies, particularly those responsible for enforcement of environmental standards, and are made available for review and comment by the general public. While the EIS review process does not allow any agency or group to directly stop the proposed action, it does require those involved in planning to consider environmental as well as economic, production, and transportation factors in any decision-making process.

Another Federal law with the goal of minimizing potential environmental impacts is the Surface Mining Control and Reclamation Act of 1977 (SMCRA). Its primary purpose is to assure that surface mining of coal will not be conducted if the mining operations produce adverse environmental impacts or if reclamation is not feasible. The Office of Surface Mining (OSM), which is responsible for enforcing the provisions contained in SMCRA, issued regulations for surface coal mining and reclamation operations (Federal Register 13 March 1979). The regulations set forth criteria for designating lands as unsuitable for mining. Lands are considered unsuitable if mining operations would:

> Damage important historical, cultural, scientific, aesthetic, or natural areas,
>
> Reduce long-range productivity of water supply or of food or fiber products,
>
> Endanger life and property by affecting natural hazard lands such as areas subject to frequent flooding or areas of unstable geology, or
>
> Violate existing State or local land use plans.

For lands declared suitable for mining, the regulations require that proposed surface coal mining operations meet all NAAQS and any other applicable Federal or State air quality standards.

The OSM regulations require two separate components addressing air quality in a mine permit application:

> An ambient air quality monitoring program is needed to evaluate the impact of surface coal mining operations on local particulate levels. Monitoring is discussed in the following section and the baseline data section.
>
> A fugitive dust control plan is needed to aid in achieving and maintaining the NAAQS and all other applicable Federal and State standards. The regulations provide a list of 19 dust control measures that could be used depending on applicable performance standards, climate, existing air quality, mine size, and type of operation. Dust control strategies are discussed in the mitigation measure section.

Permitting Requirements

Because permitting requirements are a function of project design and because of differences in approach necessitated by the availability of data and specific agency requirements, no comprehensive listing of air quality permitting requirements for surface coal mines is possible. Figure 1 depicts selected Federal permitting requirements for sources subject to PSD and for sources locating in areas where existing ambient concentrations exceed the NAAQS. State permitting requirements include many of the same provisions, and some provisions are common to almost all permit applications. The common requirements relate to justifying the control technology used in the mine design, monitoring to determine existing air quality and meteorological conditions, and mathematical modeling to determine the impact against applicable ambient standards. These activities are discussed fully in later sections of this document. Mine permitting requirements specific to each State's implementation plan are detailed in that section.

Baseline Meteorological Data

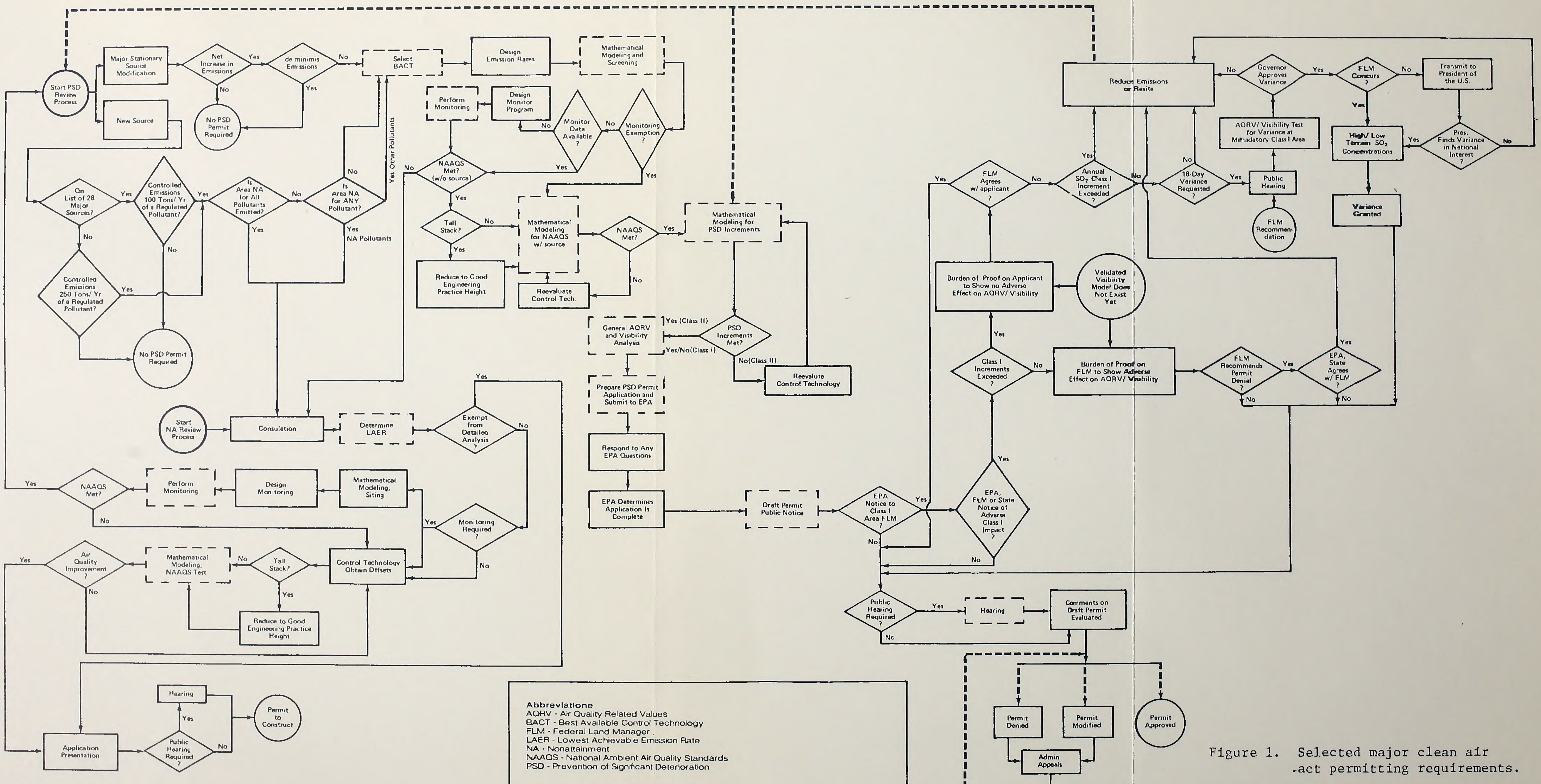
This is collected to satisfy requirements for on-site climatological design data and site-specific atmospheric transport and dispersion data used in the computer modeling assessment. A field monitoring program may not be necessary if applicable data is available from nearby sources, and if the agency agrees to the use of the existing data in the impact analysis. If field monitoring is required to provide a meteorological data base for the modeling, a full-year program is required. Few, if any, exceptions to this requirement are granted. Continuing meteorological monitoring after the start of operations is often a permit requirement.

Parameters monitored include wind speed and direction, temperature, precipitation, and some means to infer atmospheric stability. Additional details may be found in Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA 1980b).

Baseline Air Quality Data

Data substantiating existing air quality conditions at the proposed project site are required in the permit application. The data must be obtained at locations where the maximum impacts of the new facility on its own, as well as in combination with other nearby sources, are projected to occur.

SELECTED MAJOR CLEAN AIR ACT PERMITTING REQUIREMENTS IN PREVENTION OF SIGNIFICANT DETERIORATION AND NONATTAINMENT AREAS



Start PSD Review Process
Major Stationary Source Modification
New Source
Net Increase in Emissions
Yes
No
No PSD Permit Required
de minimis Emissions
No
Yes
Select BACT
Design Emission Rates
Mathematical Modeling and Screening
Perform Monitoring
Design Monitor Program
Monitor Data Available ?
No
Monitoring Exemption ?
No
Yes
NAAQS Met? (w/o source)
No
Yes
Yes
Tall Stack?
No
Yes
Reduce to Good Engineering Practice Height
Mathematical Modeling for NAAQS w/ source
NAAQS Met?
Yes
No
Reevaluate Control Tech.
Mathematical Modeling for PSD Increments
PSD Increments Met?
Yes (Class II)
Yes/No(Class I)
No(Class II)
General AQRV and Visibility Analysis
Reevalute Control Technology
Prepare PSD Permit Application and Submit to EPA
Respond to Any EPA Questions
EPA Determines Application Is Complete
Draft Permit Public Notice
On List of 28 Major Sources?
Yes
No
Controlled Emissions 100 Tons/Yr of a Regulated Pollutant?
Yes
No
Controlled Emissions 250 Tons/Yr of a Regulated Pollutant?
Yes
No PSD Permit Required
Is Area NA for All Pollutants Emitted?
No
Yes
Is Area NA for ANY Pollutant?
No
Yes NA Pollutants
Yes Other Pollutants
Start NA Review Process
Consultation
Determine LAER
Exempt from Detailed Analysis ?
Yes
No
Monitoring Required ?
Yes
No
Mathematical Modeling, Siting
Design Monitoring
Perform Monitoring
NAAQS Met?
Yes
No
Control Technology Obtain Offsets
Tall Stack?
No
Yes
Reduce to Good Engineering Practice Height
Mathematical Modeling, NAAQS Test
Air Quality Improvement ?
Yes
No
Application Presentation
Public Hearing Required ?
Yes
No
Hearing
Permit to Construct
EPA Notice to Class I Area FLM ?
Yes
No
EPA, FLM or State Notice of Adverse Class I Impact ?
Yes
No
Class I Increments Exceeded ?
Yes
No
Burden of Proof on Applicant to Show no Adverse Effect on AQRV/Visibility
Validated Visibility Model Does Not Exist Yet
Burden of Proof on FLM to Show Adverse Effect on AQRV/Visibility
FLM Agrees w/ applicant ?
Yes
No
Annual SO₂ Class I Increment Exceeded ?
Yes
No
18-Day Variance Requested ?
Yes
No
Public Hearing
FLM Recommendation
AQRV/Visibility Test for Variance at Mandatory Class I Area
Reduce Emissions or Resite
Governor Approves Variance
No
Yes
FLM Concurs ?
No
Yes
Transmit to President of the U.S.
Pres. Finds Variance in National Interest ?
Yes
No
High/Low Terrain SO₂ Concentrations
Variance Granted
FLM Recommends Permit Denial ?
Yes
No
EPA, State Agrees w/ FLM ?
Yes
No
Public Hearing Required ?
Yes
No
Hearing
Comments on Draft Permit Evaluated
Permit Denied
Permit Modified
Permit Approved
Admin. Appeals
Judicial Review
Remanded
Affirmed

Abbreviations
AQRV - Air Quality Related Values
BACT - Best Available Control Technology
FLM - Federal Land Manager
LAER - Lowest Achievable Emission Rate
NA - Nonattainment
NAAQS - National Ambient Air Quality Standards
PSD - Prevention of Significant Deterioration

Source:
Adapted from Environmental Research & Technology, Inc., "The Impact of Air Quality Permit Procedures on Industrial Planning and Development" (Prepared for the Business Roundtable Air Quality Project), November 1980

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FOR STERN BROS., INC., DECEMBER 1980
(Redrafted by Morrison-Knudsen Company, 1982)

Figure 1. Selected major clean air act permitting requirements.

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For a surface coal mine application, particulate monitoring is generally the only required parameter, unless a major combustion source (e.g. dryer or boiler) is located on-site.

Ordinarily, particulate monitoring programs extend for one year, but agency approvals of shorter monitoring programs (four months minimum) are sometimes made if adequate meteorological data already exists. Samples are taken by means of a high-volume (hi-vol) air sampler which draws air through glass fiber filters. The change in filter weight is used to infer particulate concentrations. Samples are taken every three or six days according to agency requirements on a nationally coordinated schedule.

Best Available Control Technology (BACT)

For each source and each Clean Air Act pollutant subject to PSD review, a BACT emission standard is required as a PSD permit condition. The BACT emission standard must be at least as stringent as the applicable New Source Performance Standard and is determined by EPA on a case-by-case basis, taking into account energy availability, environmental and economic impacts, and other costs. Independent of the PSD requirement, BACT is required in virtually all State regulations.

The Federal definition of BACT is given in the Federal Register of 7 August 1980 (45 FR 52736-7). State definitions are similarly worded.

> 'Best Available Control Technology' means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs determines is achievable for such source of modifications through application of production processes or available methods, systems, and techniques...

It is important to note that BACT is determined by the agency after considering the relative significance of environmental, economic, and energy impacts which may be associated with various options which may be available. An analysis of these options is prepared by the mine developer and presented in the permit application. Each project and each emission source within the mine is considered on a case-by-case basis.

A discussion of which controls are commonly interpreted as BACT is provided in the mitigation section.

STATE IMPLEMENTATION

Application of the Federal air quality regulations varies from State to State. Each State files a SIP with the EPA that details how the State will comply with NAAQS and PSD requirements.

Some States administer the Federal PSD program through the State agency, because the SIP has been approved and the State agency has demonstrated to EPA that it has the technical expertise and facilities to approve and administer the Federal permits. In those States, only one application is required for a PSD source and that application is made to the State agency.

Many States have adopted air quality standards that are the same as or more restrictive than the NAAQS. Of the four States considered in this report, the State of Wyoming has adopted ambient air quality standards which are identical to the NAAQS while the other three have air quality standards that deviate from NAAQS. The ambient air quality standards for the States of Wyoming, Montana, North Dakota, and Colorado, are shown in Table 3 (A-D).

Summarized below are background material and highlights on the enabling legislation, the administrative agencies, and the permit approval cycle for the States of Wyoming, Montana, North Dakota, and Colorado.

Wyoming

The Wyoming Air Quality Act was enacted to ensure and protect good air quality throughout the State and is intended:

> To achieve and maintain such levels of air quality as will protect human health and safety and, to the greatest degree practicable, prevent injury to plant and animal life and property, foster the comfort and convenience of the people, promote the economic and social development of this State, and facilitate the enjoyment of the natural attractions of this State... (Wyoming Environmental Quality Act 1973).

To meet these ends and provide a coordinated statewide air pollution control effort, the act created the Environmental Quality Council and the Air Quality Division within the Wyoming Department of Environmental Quality. The primary responsibility of the council is to promulgate and adopt appropriate air quality regulations as needed to administer the act. The Wyoming Air Quality Regulations were issued in 1973 and were most recently revised in April 1981.

The State of Wyoming requires a PSD-type construction permit for any new source of air emissions. The PSD permit for a major source is obtained from the State agency, which has full PSD jurisdiction. A permit application filed by the applicant initiates the permitting process. The application must describe the proposed source including control equipment and efficiencies, proposed project schedule, stack parameters, product flow rate, and air quality impact modeling. Similar to the EPA, Wyoming requires at least one year of site-specific air quality monitoring data if representative data from an existing monitor is unavailable. This data must be included in the permit application. An engineering evaluation is then performed by the Air Quality Division based on information contained in the application. The evaluation includes a modeling analysis of air quality impacts for comparison with NAAQS and, if the source is subject to PSD requirements, with PSD increments. The engineering evaluation can take 60 days or longer.

After completing the agency evaluation, comments on the proposed development are accepted from the public for a period of 30 days. If required, a public hearing is scheduled following the public comment period.

TABLE 3-A. WYOMING AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	Ambient Standards
Oxidant (ozone)[a]	1 hour	160 μg/m^3[c]
Carbon monoxide	8 hour	10 mg/m^3[c]
	1 hour	40 mg/m^3[c]
Nitrogen dioxide	Annual	100 μg/m^3[c]
	1 hour	None
Sulfur dioxide[b]	Annual	60 μg/m^3
	24 hour	260 μg/m^3[c]
	3 hour	1300 μg/m^3[c]
Suspended particulate matter	Annual (geometric mean)	60 μg/m^3[c]
	24 hour	150 μg/m^3[c]
Lead	Calendar quarter	None
Hydrocarbons	3 hour (6-9 AM)	160 μg/m^3[c]
Visible particulate emission standard		
Stack emissions		20% Opacity
Diesel engines		30% Opacity
Coefficient of haze	Annual (geometric mean)	0.4/1,000 Linear-ft
Settleable particulates		
Residential		5 g/m^2 - month
Industrial		10 g/m^2 - month

---

[a] Not to be exceeded more than 1% of hours in 3-month period.

[b] Other sulfur regulations (e.g., standards for H_2S, acid mist, SO_2 at source, etc.) also apply.

[c] Not to be exceeded more than once per year.

TABLE 3-B. MONTANA AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	Ambient Standards
Oxidant (ozone)[a]	1 hour	200 $\mu g/m^3$[c]
Carbon monoxide	8 hour	10 mg/m^3[c]
	1 hour	26 mg/m^3[c]
Nitrogen dioxide	Annual	100 $\mu g/m^3$
	1 hour	600 $\mu g/m^3$[c]
Sulfur dioxide[b]	Annual	60 $\mu g/m^3$
	24 hour	260 $\mu g/m^3$[c]
	1 hour	1276 $\mu g/m^3$[c]
Suspended particulate matter	Annual (geometric mean)	75 $\mu g/m^3$
	24 hour	260 $\mu g/m^3$[c]
Lead	Calendar quarter	1.5 $\mu g/m^3$
Hydrocarbons	3 hour (6-9 AM)	None
Visible particulate emission standard		
Stack emissions		20% Opacity
Diesel engines		None
Coefficient of haze	Annual (geometric mean)	$3 \times 10^{-5}\ m^{-1}$ (scattering coefficient) for PSD Class I areas only
Settleable particulates		
Residential		10 g/m^2 - month
Industrial		10 g/m^2 - month

---

[a] Not to be exceeded more than 1% of hours in 3-month period.

[b] Other sulfur regulations (e.g., standards for H_2S, acid mist, SO_2 at source, etc.) also apply.

[c] Not to be exceeded more than once per year.

TABLE 3-C. NORTH DAKOTA AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	Ambient Standards
Oxidant (ozone)[a]	1 hour	160 µg/m^3[c]
Carbon monoxide	8 hour	10 mg/m^3[c]
	1 hour	40 mg/m^3[c]
Nitrogen dioxide	Annual	100 µg/m^3
	1 hour	200 µg/m^3[c]
Sulfur dioxide[b]	Annual	60 µg/m^3
	24 hour	260 µg/m^3[c]
	1 hour	715 µg/m^3[c]
Suspended particulate matter	Annual (geometric mean)	60 µg/m^3
	24 hour	150 µg/m^3[c]
Lead	Calendar quarter	1.5 µg/m^3
Hydrocarbons	3 hour (6-9 AM)	160 µg/m^3[c]
Visible particulate emission standard		
Stack emissions		20% Opacity
Diesel engines		None
Coefficient of haze	Annual (geometric mean)	0.4/1,000 Linear-ft Areas only
Settleable particulates		
Residential		15 tons/mile^2- 3 month
Industrial		30 ton/mile^2 - 3 month

---

[a] Not to be exceeded more than 1% of hours in 3-month period.

[b] Other sulfur regulations (e.g., standards for H$_2$S, acid mist, SO$_2$ at source, etc.) also apply.

[c] Not to be exceeded more than once per year.

TABLE 3-D. COLORADO AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	Ambient Standards		
Oxidant (ozone)[a]	1 hour	160 $\mu g/m^3$[c]		
Carbon monoxide	8 hour	10 mg/m^3[c]		
	1 hour	40 mg/m^3[c]		
Nitrogen dioxide	Annual	100 $\mu g/m^3$		
	1 hour	None		
Sulfur dioxide[b]		Class I[d]	Class II[d]	Class III[d]
	Annual	2	10	15
	24 hour	5	50	100
	3 hour	25	300	700
Suspended particulate matter		Primary	Secondary	
	Annual (geometric mean)	75 $\mu g/m^3$[e]	60 $\mu g/m^3$	
	24 hour	260 $\mu g/m^3$[c]	150 $\mu g/m^3$[ce]	
Lead	Calendar quarter	None		
Hydrocarbons	3 hour (6-9 AM)	None		
Visible particulate emission standard				
Stack emissions		20% Opacity		
Diesel engines		30-40% Opacity		
Coefficient of haze	Annual (geometric mean)	None		
Settleable particulates				
Residential		None		
Industrial		None		

---

[a] Not to be exceeded more than 1% of hours in 3-month period.

[b] Other sulfur regulations (e.g., standards for H_2S, acid mist, SO_2 at source, etc) also apply.

[c] Not to be exceeded more than once per year.

[d] Values are $\mu g/m^3$ allowable incremental increase over September 4, 1975, baseline.

[e] Annual primary and 24-hour secondary standards are used as permit compliance standards.

Montana

The Montana Clean Air Act of 1967 was enacted to ensure and protect good air quality throughout Montana. The legislation is intended:

> To achieve and maintain such levels of air quality as will protect human health and safety and, to the greatest degree practicable, prevent injury to plant and animal life and property, foster the comfort and convenience of the people, promote the economic and social development of this State, and facilitate the enjoyment of the natural attractions of this State... (Montana Code Annotated, 1975, Chapter 2, Part 1 § 75-2-102(1)).

To meet these ends and provide a coordinated statewide air pollution control effort, the act names the Board of Health and Environmental Sciences and the Environmental Sciences Division within the Montana State Department of Health and Environmental Sciences as the administrators of the act. The primary responsibility of the department is to promulgate and adopt air quality regulations needed for the administration. The Montana Clean Air Act regulations were most recently revised in July 1979.

The PSD permit for a major source located in Montana is legally obtained from the EPA regional office in Denver, Colorado. However, the Montana Environmental Services Division takes responsibility for receiving the PSD application and works in close conjunction with the EPA on the final decision. Montana is very near assuming PSD authority at the time of this writing.

The State of Montana requires a PSD-type construction permit for any new source of air emissions. A permit application filed by the applicant initiates the permitting process. The application must describe the facility in detail including control equipment and efficiencies, stack parameters, and product flow rate. An engineering evaluation is then performed by the Environmental Services Division staff based on information contained in the application. The evaluation includes a modeling analysis of air quality impacts for comparison with NAAQS and, if the source is subject to PSD, with PSD increments. Air quality modeling may also be required from the applicant. During the agency evaluation, comments on the proposed development are accepted from the public. Interested parties are advised of the preliminary determination and allowed a 15-day comment period.

The total time required for the permitting process in Montana is limited by law to 60 days from the date that the complete application is filed. Extensions may be obtained if special problems arise.

North Dakota

The 1969 North Dakota Air Pollution Control Act was enacted to promote and ensure good air quality throughout the State. In the declaration, legislative intent is summarized as follows:

> To achieve and maintain the best air quality possible consistent with the best available control technology to protect human health, welfare, and

> property, to prevent injury to plant and animal life, to promote the economic and social development of this State, to foster the comfort and convenience of the people, and to facilitate the enjoyment of the natural attractions of this State... (North Dakota Century Code, 1969, Title 23 § 23-25-101.1).

To meet these ends and to provide a coordinated statewide air pollution control effort, the act created the Air Pollution Control Advisory Council and the Environmental Engineering Department within the North Dakota State Department of Health. The primary responsibility of the council is to promulgate and adopt appropriate air quality regulations as needed for administration of the act. The North Dakota regulations were enacted in 1969 and were most recently revised in 1982.

Currently, the PSD permit for a major source located in North Dakota is obtained from the EPA regional office in Denver, Colorado. The State has incorporated the PSD regulations in their entirety into the State regulations and, in addition, has designated coal mines as "designated air contaminant sources," which are, therefore, subject to additional State regulations. Coal crushers, conveying, and loading equipment are regulated separately as "coal preparation facilities."

The State of North Dakota requires a construction permit for any new source of air emissions including surface mines. A permit application filed by the applicant initiates the permitting process. The application must describe the type of source including control equipment and efficiencies, engineering drawings, facility specifications, estimated emissions, and projected air quality impacts. An evaluation is then performed by Department of Health staff based on information contained in the application. The evaluation includes a modeling analysis of air quality impacts for comparison with NAAQS and, if the source will be located in an attainment area, with PSD increments. The engineering evaluation can take up to one month.

After completing the agency evaluation, comments on the proposed development are accepted from the public for a 30-day period and the applicant is allowed an opportunity to respond to the comments in writing. The entire permitting process can require from three to six months for completion.

North Dakota also requires an operating permit, which allows performance testing, ambient monitoring, record keeping, and reporting and is valid for three years for mines. Application is made at least 30 days prior to start-up.

Colorado

The Colorado Air Quality Control Act was implemented to protect the health and general welfare of the citizens of the State. The legislative declaration includes the following:

> To achieve the maximum degree of air purity in every portion of the State, to attain and maintain the national ambient air quality standards, and to prevent the significant deterioration of air quality in those portions of

> the State where the air quality is better than the national ambient air quality standards. To that end, it is the purpose of this article to require the use of all available practical methods which are technologically feasible and economically reasonable so as to reduce, prevent, and control air pollution throughout the State... (Colorado Revised Statutes, 1973, Title 25, Article 7-102).

To achieve these objectives, the act created the Air Quality Control Commission and the Air Pollution Control Division within the Colorado Department of Health. The commission is granted broad powers under the act to implement and administer the SIP, emissions control regulations, a PSD program, a permitting and enforcement program for all fixed emission sources, and a motor vehicle control program. The Colorado air quality regulations were issued in 1973 and were most recently amended in 1981.

Although Colorado has a State PSD program within its State regulations, the Federal PSD permit for sources located in Colorado is obtained from the EPA Regional Office in Denver. However, the Colorado Air Pollution Control Division has a well-established and technically explicit methodology for assessing impacts from mine-related fugitive dust and EPA works in close harmony with the State agency in evaluating Colorado permit applications.

The State of Colorado requires a PSD-type construction permit for any new source of air emissions. A Notice of Intent (NOI) filed by the applicant initiates the permitting process. The NOI must describe the type of source including control equipment and efficiencies, stack parameters and product flow rate. Similar to the EPA, Colorado requires at least one year of site-specific air quality monitoring data if representative data from an existing monitor is unavailable. This data must be available at the time the NOI is filed. An engineering evaluation, sometimes taking up to 60 days, is then performed by air pollution control division staff based on information contained in the NOI. The evaluation includes a modeling analysis of air quality impacts for comparison with NAAQS and with PSD increments. Air quality modeling can also be submitted by the applicant.

Within 15 days after completing the agency evaluation, public comments are solicitied, and are then accepted for 30 days. If required, a public hearing is scheduled following the public comment period.

Within 30 days of the close of the comment period, the State must notify the applicant of deficiencies or the permit is automatically granted. An agency inspection of the facility is required after construction and prior to startup.

MINE OPERATIONS PRODUCING FUGITIVE EMISSIONS

Fugitive emissions are defined as "those pollutant emissions that are not normally vented through a controlled opening, such as a stack or baghouse vent." The majority of mining emissions are fugitive and are comprised of both gaseous and particulate matter. Particulate emissions are commonly referred to as fugitive dust, once airborne, as they are called "total suspended particulates or TSP." Significant gaseous pollutants are carbon monoxide, sulfur and nitrogen oxides, and hydrocarbons resulting from blasting and diesel equipment operation. In addition to these pollutants, lead also is emitted by gasoline engine operation.

Since the gaseous pollutants are emitted in relatively small quantities, the focus of attention for mining air quality impacts is generally on fugitive dust emissions. In this and other sections, gaseous pollutant emissions will be only briefly addressed.

Any mining activity that moves rock, coal, topsoil, or other dry material produces fugitive dust. In addition, particulate matter is emitted from vehicle exhaust and gaseous emissions are emitted from blasting and vehicle exhaust. This section provides a brief description of these mining activities and the means by which airborne particulate and gaseous emissions are produced. Methods and effectiveness for emissions control are discussed in the mitigation section.

SOURCES OF FUGITIVE DUST

Airborne dust is generated by mining operations and coal-handling facilities. Following is a list of typical mining operations and handling facilities which produce fugitive dust as well as a brief description of each operation and facility:

Fugitive Dust Sources

From Mining
- Facility site preparation and construction
- Topsoil removal and placement
- Overburden drilling, blasting, removal and dumping
- Coal drilling, blasting, and removal
- Material hauling
- Spoils grading
- Reclamation grading and tilling
- Exposed area and topsoil stockpile wind erosion
- Nonmining vehicle traffic
- Road maintenance and watering

From Facilities
- Crusher load-in
- Crushing and screening
- Conveying and conveyor transfers
- Coal storage pile stacking, wind erosion, and reclaiming
- Railcar loading and wind erosion

Mining

Coal mining begins with a construction phase which may last from a few months to more than a year. During this time, a facility site is cleared of vegetation, water-control facilities are constructed and roads are created. Facilities for processing and loading coal into trains (or to a mine-mouth power plant) are constructed. Fugitive dust results from road building and vehicular activity in the construction area. Because of the temporary nature of construction emissions, air quality impacts are short-lived.

Operation of the mine begins with topsoil stripping and associated land clearing. Topsoil is generally removed using scrapers which strip the topsoil with a blade and carry it to a topsoil storage or reclamation area. Topsoil is either stored for later use, or transferred to the spoils area for immediate reclamation. Commonly used scrapers have load capacities ranging from 20 to 44 cubic yards.

Overburden material is usually fragmented by blasting before removal. Drill trucks are used to drill regularly spaced holes, generally to depths around 30 feet. Dust emissions for drilling vary considerably depending on the level of the water table; they are predominantly fines, resulting from rock abrasion. An ammonium nitrate fuel oil (ANFO) mixture is commonly used as an explosive. The holes are detonated in a rapid sequence which results in even fragmentation of the rock. Although individual blast plumes are large, blasting frequency is generally once a day or less, so air quality impacts are not great. The blasting operation also emits various gasses into the atmosphere (see gaseous emission sources).

The next step, overburden removal, is the largest activity at most coal mines. Overburden is removed by dragline, shovel, scraper, dozer, or a combination thereof. Using draglines in the typical strip-mine operation, overburden is removed from a relatively narrow cut and dumped on an adjacent spoils area. Fugitive dust is primarily emitted from scooping material into the bucket and from material falling from the bucket onto the spoils pile. Figure 2 illustrates a dragline operation.

In an open-pit coal mine, shovels are used to remove overburden. Since the pit is usually quite large and the spoils area is far from the overburden removal area, haul trucks are used to transport the overburden. Dust results primarily from the scooping of material by the shovel and the shovel loading overburden into haul trucks. Figure 3 depicts a shovel/truck mining operation.

In open-pit mines with thin layers of overburden, scrapers and dozers are used for removal. Scrapers are capable of hauling overburden to a spoils area, but dozers are limited to pushing overburden from the working area down to the pit floor. Dust results from scraper and dozer blades pushing the overburden material and from scrapers hauling the overburden.

Overburden removal also encompasses removing interbedded waste rock, i.e., rock between the coal seams. The method used for removal of this material depends on its thickness; a dragline or shovel may be used if the bed is thick (more than 10 feet), or thin beds may be removed by scraper and/or dozer. Like overburden, coal is generally blasted for fragmentation before it is removed. Drilling and blasting emissions for coal are similar to emissions for overburden.

Coal is generally removed by shovel, front-end loader, scraper, or a combination of these. Shovels usually have a larger bucket capacity (5 to 35 cubic yards) than front-end loaders, but front-end loaders can be used to scoop coal rubble

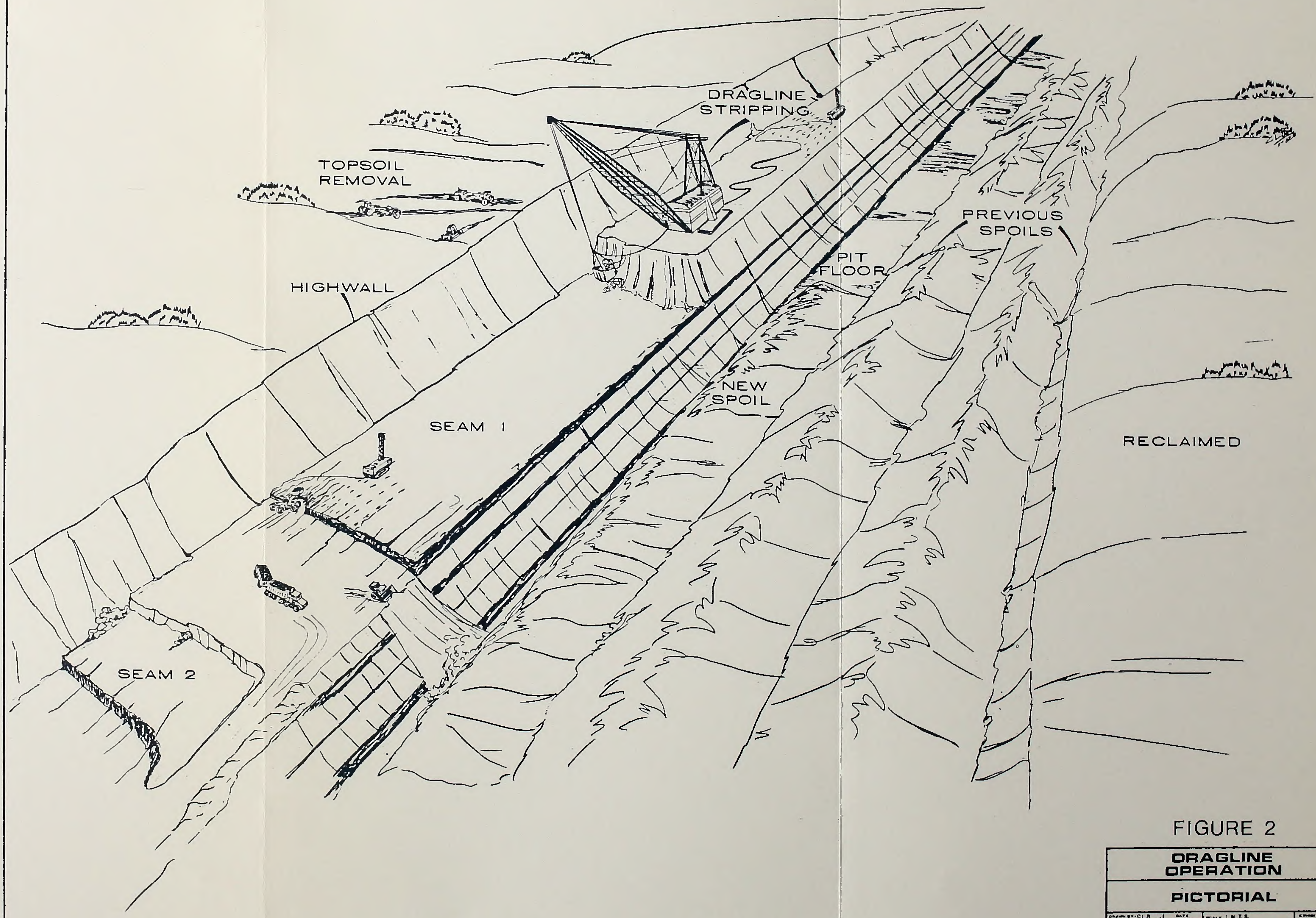

FIGURE 2

ORAGLINE OPERATION

PICTORIAL

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APP'D BY:		DATE JANUARY, 1982	
DESIGN BY:	DATE	DWG. NO.:	
APP'D BY:			

MORRISON-KNUDSEN COMPANY, INC.
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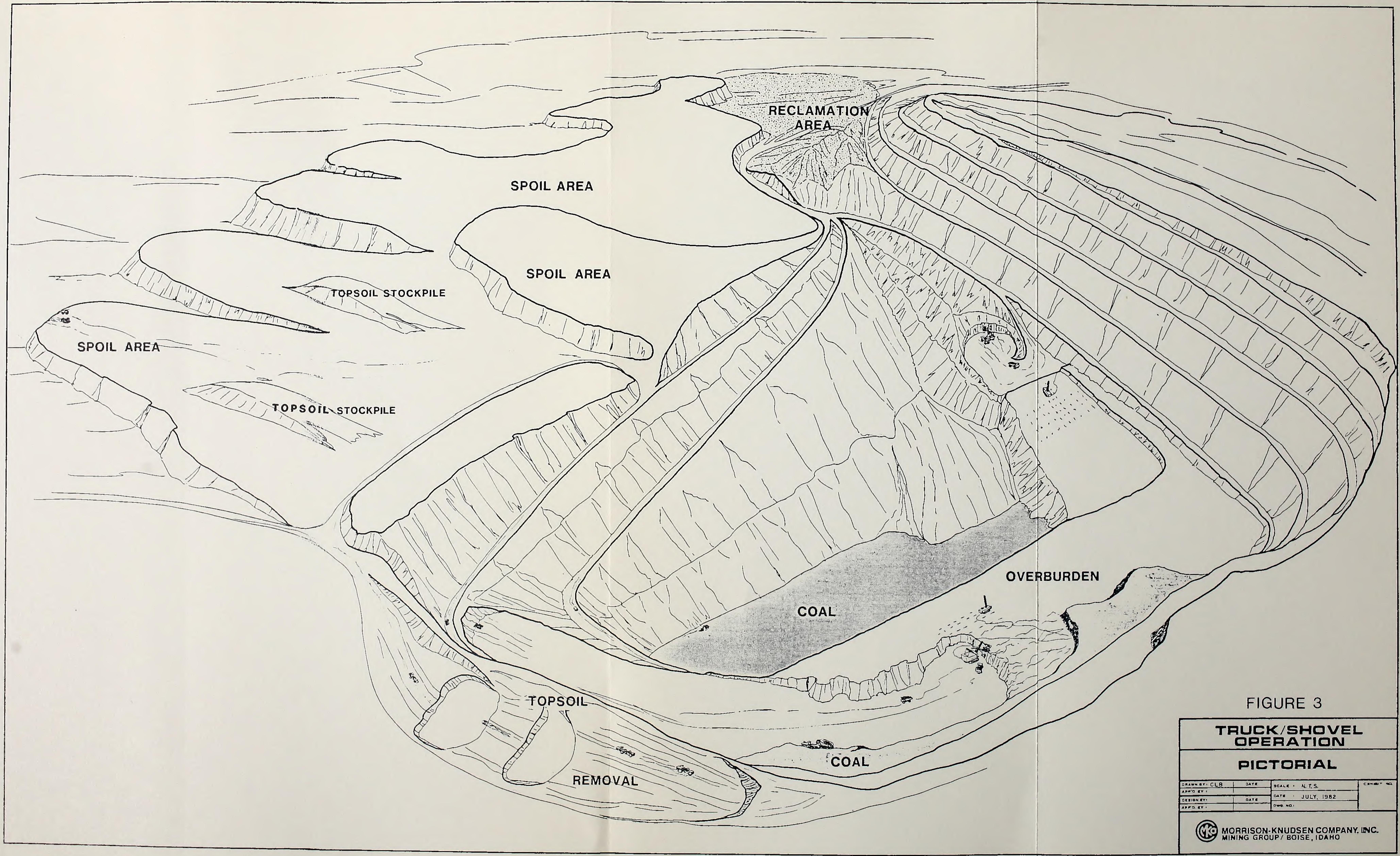

FIGURE 3

TRUCK/SHOVEL OPERATION

PICTORIAL

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DATE
APP'D BY:
DESIGN BY:
DATE
APP'D BY:
SCALE : N.T.S.
DATE : JULY, 1982
DWG. NO.:
EXHIBIT NO.

MORRISON-KNUDSEN COMPANY, INC.
MINING GROUP / BOISE, IDAHO

into a pile during the removal operation. Scrapers are used when coal seams are thin. For both shovels and front-end loaders, trucks are used to haul the coal to the coal storage or train-loading area. In some mines, however, the coal is loaded directly into a feeder-breaker crushing unit in the pit and is transported to the storage and train area by conveyor.

When haul trucks are used, the truck types are the same as those used for overburden hauling; they may be end-dump or bottom-dump types and range in capacity from 35 to 180 tons. Haul truck dust emissions result from driving over unpaved roads and pit areas. Depending on the size of the trucks, average haul distances, and the amount of traffic, haul truck emissions are often the largest single source of fugitive dust at a mine.

When a portion of the pit has been filled with overburden material, graders and dozers are used to contour the surface to prepare for reclamation. This operation consists of grading the peaks of the spoil piles to a constant level when draglines are used and smoothing out the truck dumping area when shovels and/or scrapers are used. After the spoils have been leveled, topsoil is placed on top by scrapers and smoothed by graders and dozers. The topsoil usually comes from topsoil stripping operations in advance of the developing pit but may come from topsoil storage areas when required.

The land is reclaimed by seeding the topsoil with various grasses and mulching with straw or some similar organic material. This reclamation procedure involves soil tilling, which produces fugitive dust emissions.

During the time from initial topsoil stripping to final reclamation, the mine area is exposed to wind erosion. The areas with greatest disturbance from vehicle traffic are subject to the greatest wind erosion, but even exposed areas that remain undisturbed for long periods of time will produce some wind erosion emissions. Depending on the physical size of the mine and the climate of the area, wind erosion can be a significant fugitive dust source.

An additional source of fugitive dust results from nonmining vehicle traffic on unpaved or gravel roads. Light-duty trucks, commuter cars, and buses contribute fugitive emissions in significant amounts. Also all mine roads require regular maintenance using graders or dozers and regular wetting by water trucks during dry periods. This traffic also produces dust in significant amounts.

Facilities

At most coal mines, coal is brought from the pit by haul trucks and dumped into a hopper or tipple where it is fed into a primary crusher. If a conveyor system is used instead of haul trucks, the primary crusher is generally at the pit. As the coal is broken into smaller pieces, fine particles are released. Primary crushers are almost always located outside any facility buildings, so (unless a baghouse is used) crusher dust is emitted directly to the air.

After primary crushing, the coal moves by conveyor to a continuous conveyor loop between screening and secondary or tertiary crushing units. The screens allow coal sized to a predetermined diameter to fall through and move out of the conveyor loop. Coal pieces larger than the screen size continue into the secondary crusher loop until crushed to the desired size. Dust from secondary crushing and screening is finer than primary crushing and thus more susceptible to being lifted into the air.

Following crushing and screening, coal may be conveyed to a storage area or directly to train cars. During conveying, the coal may be exposed to wind erosion, although many facilities use covered conveyors. Wind erosion is greatest immediately after the coal exists from the crushing and screening units since a large quantity of suspendable fines remains mixed with the coal. Conveyor emissions are also high at transfer points where the coal drops from one conveyor onto another.

Coal storage pile fugitive emissions result from conveyor stacking at the top of the pile, wind erosion, vehicle activity on or around the pile, and reclaim from the bottom of the pile either by a continuous reclaiming system or by front-end loaders. At most coal train loading facilities and mine-mouth power plants, only a portion of the coal production passes through the storage pile. Whenever possible, coal is moved directly through the facilities without storage.

Train loading is usually done through a retractable loading chute. Dust results from the coal falling into the train cars and from wind erosion of the exposed coal surface in the cars.

GASEOUS EMISSION SOURCES

Blasting

Gaseous emissions associated with blasting come from the combustion of the explosive. The quantity of emissions and the type of gases emitted depend on the type of explosive used.

There are many types of explosives for industrial and military applications, but mining explosives are usually limited to three types: dynamite (ammonia), dynamite (gelatin), and ammonium nitrate fuel oil mixture (ANFO). The gaseous emissions resulting from the detonation of these explosives include carbon monoxide, nitrogen and sulfur oxides, and hydrocarbons.

Equipment Exhaust

All diesel and gasoline engines are sources of both particulate and gaseous pollutants. Diesel engines are sources of particulates, nitrogen and sulfur oxides, carbon monoxide, and hydrocarbons. Gasoline engines produce all of these gaseous emissions and also emit lead.

Since coal mines require large numbers of trucks, shovels, scrapers, dozers, and other diesel equipment, exhaust emissions are a significant source.

EMISSION FACTORS

Since the mid-1970s, considerable research and field work have been carried out to develop emission factors for sources of fugitive dust at coal mines. These emission factors are used to quantify mining dust emissions on a source-by-source basis. Use of the emission factors to make dust emission calculations usually requires specific mine design information (such as coal production tonnage, overburden volume, haul road lengths, etc.). The emission factors are applied to the specific mine design, resulting in an emissions inventory which can be used as input to a dispersion model.

DEVELOPMENT OF EMISSION FACTORS

Sampling Programs

The emission factors in general use today have been developed from on-site mine sampling programs, many of which have been conducted by government agencies and by research and consulting firms. Some of the more significant sampling programs are described below:

PedCo Environmental, 1973 - Fugitive dust sampled from unpaved roads, agricultural tilling, and building construction at seven sites in New Mexico, Nevada, Arizona, and California. None of the sites were mines, but the sources of dust are similar to those found at mines.

Midwest Research Institute, 1974 - Fugitive dust sampled from unpaved roads, agricultural tilling, and aggregate storage piles in Kansas and Ohio.

PedCo Environmental, 1978 - Fugitive dust sampled from sources at five coal mines in Montana, North Dakota, Wyoming, and Colorado. Sources sampled were haul roads, overburden removal by dragline, overburden and coal removal by shovel, overburden and coal blasting, overburden and coal truck dumping, coal storage, overburden and coal drilling, fly-ash dumping, train loading, topsoil removal, and coal handling by front-end loader.

Midwest Research Institute, 1978 - Fugitive particulates sampled from process and open dust sources at iron and steel plants. The study relates to coal mine emissions since coal is used in large quantities as the furnace fuel at iron and steel plants. Sources sampled were unpaved and paved roads, coal stacking and loading, coal storage pile material handling, coal storage pile wind erosion, and exposed area wind erosion.

Midwest Research Institute, 1979 - Conducted an expanded sampling program for open sources of fugitive dust at iron and steel plants. Particular attention was given to a statistical analysis of the reliability of emission factors developed in the MRI 1978 sampling study. Modifications of the earlier emission factors were made based on the expanded data set.

PedCo Environmental and Midwest Research Institute, 1981 - Fugitive dust sampled from sources at three coal mines in the Fort Union area (North Dakota), Powder River Basin (Montana-Wyoming), and San Juan River (New Mexico-Arizona).

Sources sampled were overburden drilling, overburden and coal blasting, coal loading by shovel or front-end loader, overburden and coal bulldozing, overburden removal by dragline, haul roads, scraping, grading, and overburden and coal exposed area wind erosion. Special attention was given to develop emission factors for particles in three size ranges: less than 2.5 μm (fine particulates), less than 15 μm (inhalable particulates), and total suspended particulates (TSP).

TRC Environmental Consultants, 1981 - Fugitive dust sampled at five coal mines in the Powder River Basin, Wyoming, emphasizing measurements of particle sizes and dustfall rates. Sources sampled were haul roads, coal dumping, train loading, overburden replacement, topsoil removal, and exposed area wind erosion.

PedCo Environmental, 1982 - Additional fugitive dust sampling for mining operations continues with a report expected this year. Sampling and modeling error analysis will be emphasized.

Emission factors were developed using the results of each of these studies. In some cases, notably the PedCo, 1978, study, emission factors are reported as a range of values for each source. In other studies, emission factor equations are presented that use correction factors, allowing adjustment for individual conditions.

Sampling Methodologies

The sampling methods employed for the studies listed above are generally of three types: exposure profiling, upwind-downwind, and portable wind tunnel.

Exposure Profiling

The exposure profiling technique uses a tower with several sampling intakes attached at different heights to ensure that the plume centerline is measured. Each intake passes air through a glass fiber filter which collects particulates through a range of particle sizes. The system is positioned downwind and very close to the source being monitored.

Sampling results are recorded as a mass of particulates per unit volume of air. Background concentrations are determined by locating a high volume sampler upwind of the source. The background concentration then is subtracted from the concentrations sampled at the exposure profile to determine the source contribution. Source emission rates are determined by using the Gaussian diffusion equation to back-calculate the source strength. This equation assumes that the plume of dust emitted from a source exhibits a distribution such that the TSP concentrations decrease exponentially away from the plume centerline. Further details on source strength calculations and Gaussian distribution are included in the emission calculation methodology section and the model assumptions and limitation section.

The exposure profile sampling method is applied only when the tower can span the vertical cross section of the plume and usually only when the tower can be located within 5 meters of the source (most commonly measured are haul road emissions). The design of the MRI exposure profile is shown in Figure 4.

A slightly different exposure profiling method is used for sampling blasting emissions. Since the cloud of dust from blasting is very large, the sampling intakes are suspended on a line by a balloon rather than on a tower. Again, this system ensures that the centerline of the blast plume is sampled. The balloon line is generally set up approximately 100 meters from the blast area.

Upwind-Downwind

The upwind-downwind technique uses an array of hi-vol samplers, several placed upwind of a source and several spread out downwind of the same source. The concentration contribution of the source is found by subtracting the upwind concentration from the downwind concentration. Source emission rates are determined by using the Gaussian diffusion equation to back-calculate the source strength (as described in the emission calculation methodology section). Figure 5 shows a typical upwind-downwind monitor configuration.

A variation of the upwind-downwind method was employed by TRC in their 1981 field study. Coal dumping and train loading sources were monitored by an array of samplers, as in the upwind-downwind method, but a tracer gas (SF_6) was released at the source in a known quantity. TSP and SF_6 were monitored downwind and the TSP emission rate was determined from the ratio of TSP to SF_6 concentration and the known SF_6 emission rate. This method is particularly well suited to plumes that are known to be non-Gaussian, which is probably the case for sources such as train loading and coal dumping due to the turbulence created as wind channels around mine facilities (building wake effects).

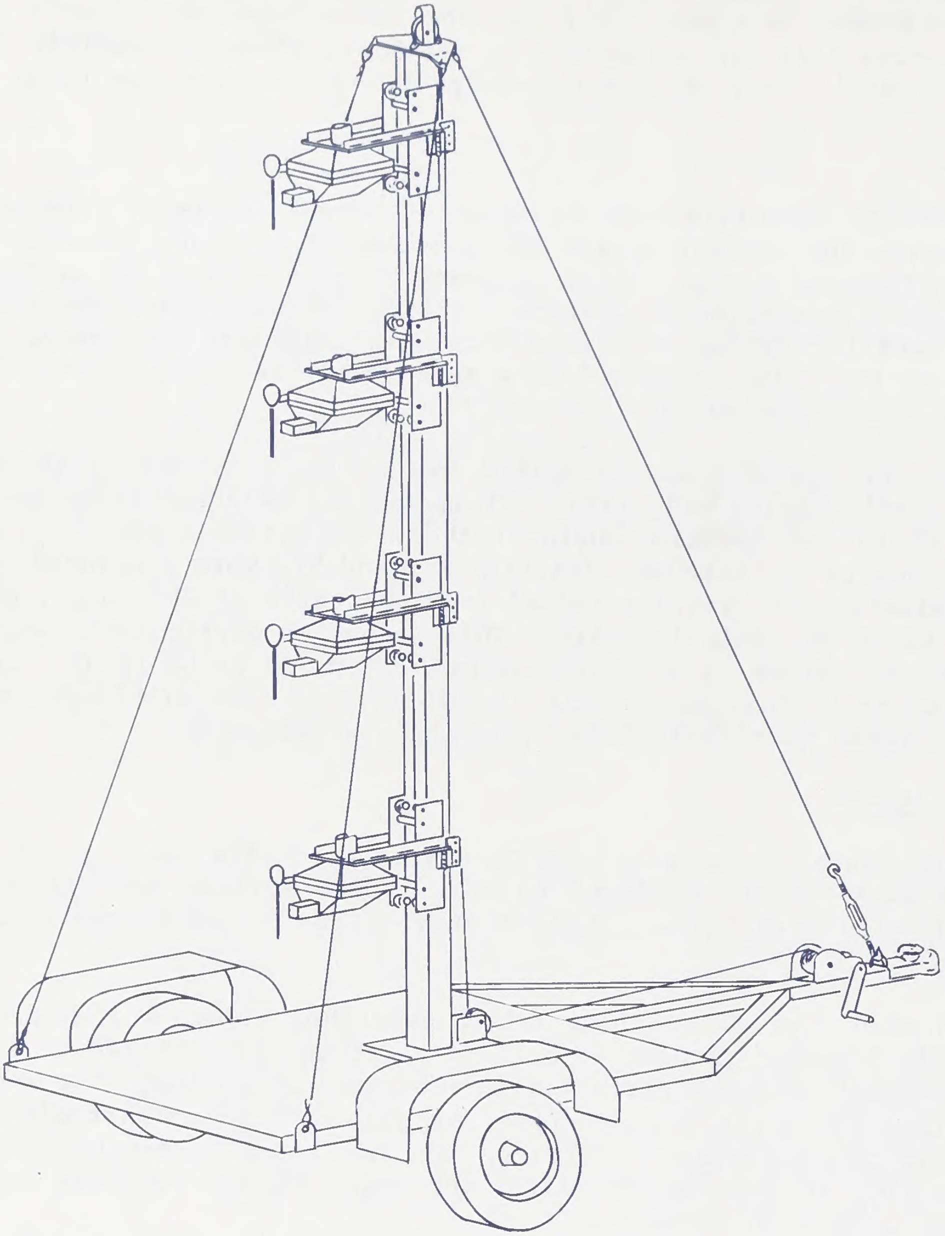
Portable Wind Tunnel

A portable wind tunnel is usually used to sample stockpile and exposed area wind erosion. The wind tunnel is placed on the exposed surface and air is blown through at measured velocities. Dust is sampled at the end of the tunnel using a hi-vol sampler.

Generally, in each type of sampling method described above, a dichotomous sampler or cascade impactor is used to collect particles distributed by size. The dichotomous sampler collects particles in two size categories, fine and coarse. The cascade impactor sifts the particles by size by forcing particles through sized slots and onto a series of filters. In some cases, particles are sized by collecting samples on a millipore filter and measuring the particle diameter in the laboratory using a microscope.

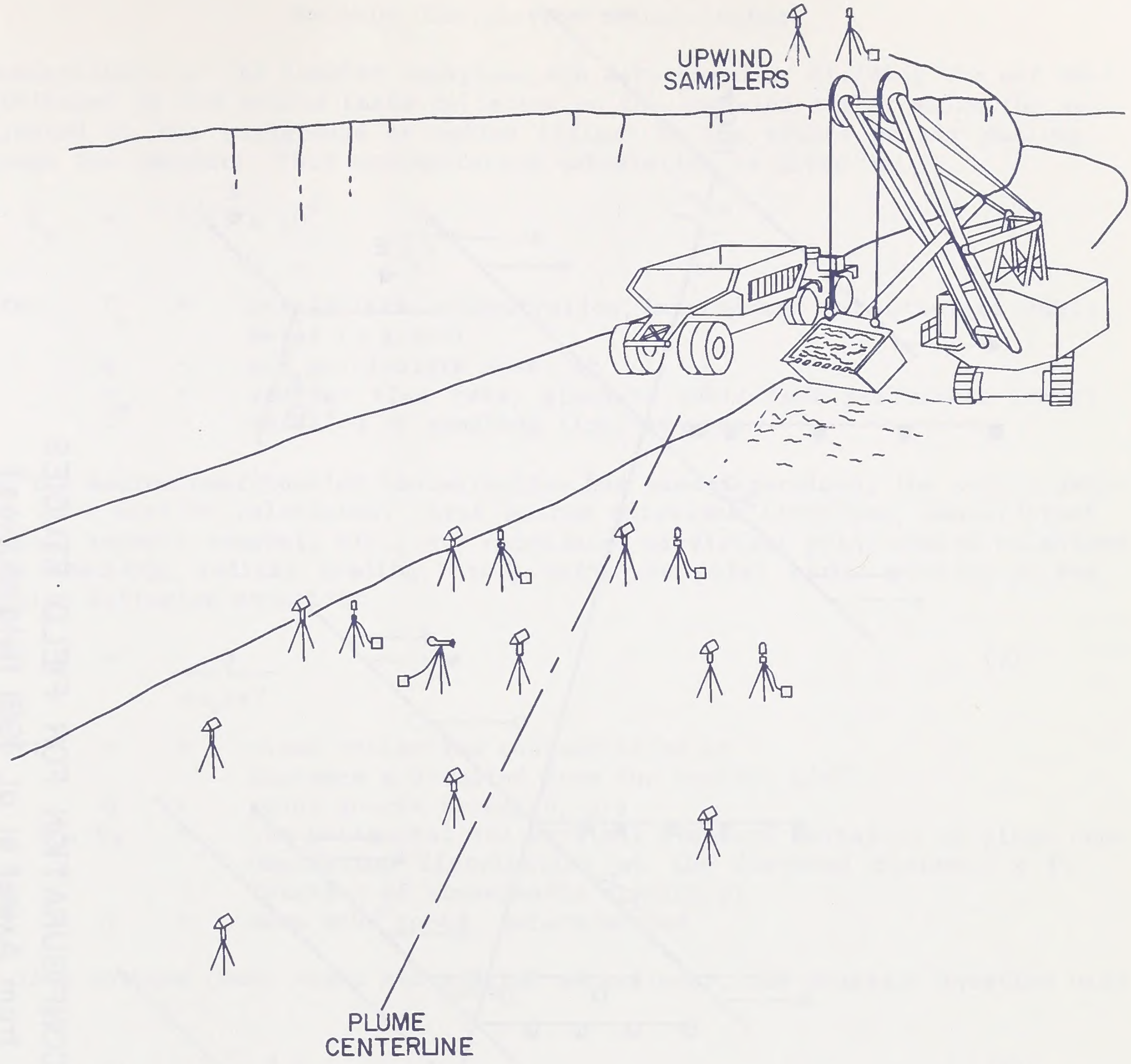
Also, in each field study, meteorological parameters are monitored during the sampling period. The meteorological monitoring is done by monitoring equipment or by visual inspection and includes wind speed and direction, cloud cover, and solar intensity.

Figure 6 displays a typical distribution of various monitoring equipment used in combination to sample source emissions.



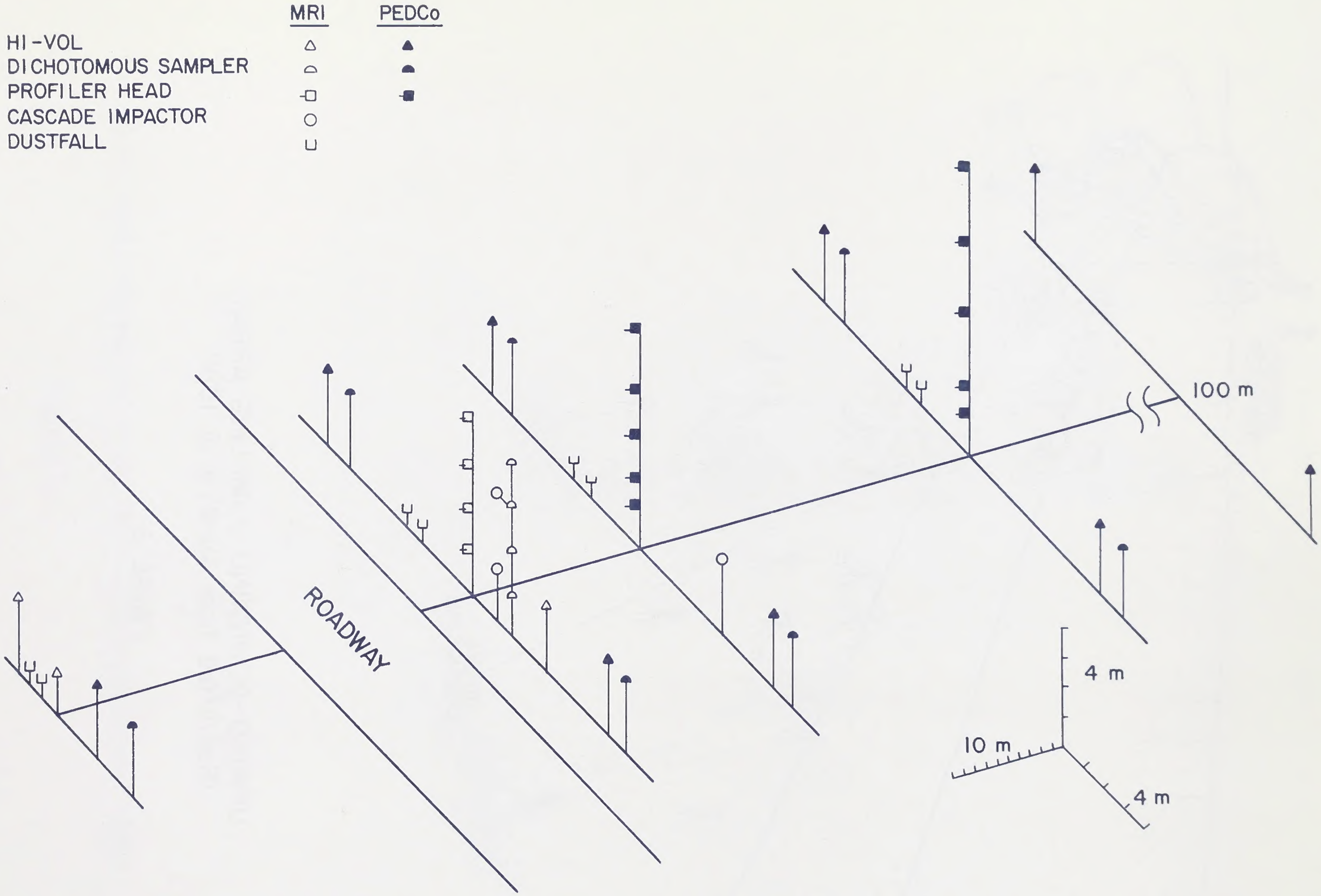
EXPOSURE PROFILER (Redrafted from Axetell et al, 1981)

FIGURE 4



UPWIND-DOWNWIND SAMPLING ARRAY
(Redrafted from Axetell et al, 1981)

FIGURE 5



SAMPLING CONFIGURATION FOR FIELD STUDIES
(Redrafted from Axetell et al, 1981 field studies)
FIGURE 6

Emission Calculation Methodologies

Concentrations at the sampler locations are determined by dividing the net mass contributed by the source (mass collected on the downwind filter minus the mass collected on the background or upwind filter) by the volume of air passing through the sampler. This concentration calculation is given by:

$$C_s = 3.53 \times 10^4 \quad \frac{m}{Q_s t} \tag{1}$$

where:
C_s = particulate concentration, micrograms per standard cubic meter (μg/scm)
m = net particulate mass, mg
Q_s = sampler flow rate, standard cubic feet per minute (scfm)
t = duration of sampling time, minutes

Once the source contribution concentration has been determined, the source emission rate must be calculated. Area source emissions (dragline, shovel/truck loading, topsoil removal, etc.) are calculated as virtual point source emissions (coal stacking, railcar loading, etc.) using the point source version of the Gaussian diffusion equation:

$$\chi = \frac{Q}{\pi \sigma_y \sigma z^u} \tag{2}$$

where:
χ = plume centerline concentration at distance x downwind from the source, g/m³
Q = point source strength, g/s
σ_y, σ_z = the horizontal and vertical standard deviation of plume concentration distribution at the downwind distance x (a function of atmospheric stability)
u = mean wind speed, meters/second

For line sources (haul roads and similar situations), the Gaussian equation used is:

$$\chi = \frac{2\,q}{\sin \phi \; 2\pi \sigma_z u} \tag{3}$$

where;
q = line source strength, g/scm
ϕ = angle between wind direction and line source
x, σ_z, u = same values as the point source equation (2)

In both of these equations the value to be calculated is the source strength (Q or q), which is used in combination with source and site characteristics to develop an emission factor or emission factor equation. For example, the source strength for haul road emissions is divided by the number of vehicles that passed by during the test, producing an emission factor expressed in pounds per vehicle-mile. Other source strengths are normalized by dividing by the process weight moved during the sampling period, producing emission factors expressed as pounds per ton moved or pounds per cubic yard moved.

In several of the field studies outlined in the emission factor development section, emission factor equations were produced that include correction factors incorporating site-specific conditions. For example, haul road emissions are usually adjusted for variances such as vehicle weight and number of wheels, as well as road silt content. The correction factors are determined by statistical analysis of the collected concentration data.

To produce emission factor equation coefficients, a set of possible correction variables (silt and moisture content, vehicle weight, wind speed, etc.) is applied to the concentration data in a statistical correlation analysis (specifically a multiple linear regression). In the analysis, data recorded for each of these variables from individual field samples are correlated with the emission rate calculated for that sample. Those variables that have a significant correlation with the calculated emission rate are included in the emission factor equation. The coefficients produced from this analysis form the emission factor equation that best correlates with the concentration data.

Emission factor equations for wind erosion sources are also developed by performing a similar statistical analysis, although the source emission rate is not determined by using a Gaussian diffusion equation. When a portable wind tunnel is used, the source emission rate is calculated directly by dividing the particulate mass collected by the air volume passing through the sampler during the sampling period. This emission rate is normalized by dividing by the surface area exposed in the wind tunnel, producing an emission rate in pounds per acre-hour.

Error Analysis

Random sampling error is introduced at a variety of points in the sampling process. Some of the sources of sampling error pointed out in the PedCo 1978 survey include the following:

- Samples taken when the sampling location criteria could not be precisely met
- Samples taken when the source plume could not be visually located, leading to an inexact measure of the time the monitor was in the plume
- High filter-loading problems
- Inconsistencies between sampling crews
- Inability to accurately monitor very low wind speeds (less than 5 mph)

Additionally, error or uncertainty is introduced in the sampling and data analysis by the following assumptions which are not always correct:

- Point and area sources are assumed stationary; this is not true for dragline and shovel operations and leads to error in source strength calculations.
- Plume particle distribution is assumed to be Gaussian (statistically normal), but probably exhibits a more uneven distribution, including a near-ground variability related to wind profiles.

-- Particle standard deviations from the plume centerline (σ_y and σ_z) are calculated from estimated and visually observed meteorological parameters.

-- Monitor locations may not be directly downwind of the source or on the plume centerline. Correction factors for this are inexact.

Quantifying the error or uncertainty involved with emission factors is generally accomplished using several statistics for uncertainty evaluation including the Student T-test, standard deviation, or fractional or standard error associated with each source emission factor.

Using these methods, employed by the PedCo (1978) and TRC (1981) field studies, the emission factors are expressed as a value, plus or minus a fractional error.

A different approach to quantifying of error was taken in the MRI 1981 field study. In this case, a predetermined acceptable margin of error (d) of 25 percent was established. Additionally, a risk (σ) of exceeding this margin of error was set at 20 percent. To meet this level of error, a two-stage sampling method is employed. In the first stage a certain number of samples (n_1) are taken for each source. A standard deviation (s_1) is calculated from this data set. Then the number of samples required for the second stage sampling of each source (n_2) is given by:

$$n = \frac{t^2 s_1^2}{d^2} \tag{4}$$

$$n_2 = n - n_1$$

where: n = number of samples required for first and second stages combined,

t = tabled t-value for risk σ and n_1-1 degrees of freedom, and

d = margin of error in estimating population mean.

As long as n_2 samples are taken in stage two, then statistically the relative error for each source will remain less than 25 percent with a 20 percent risk of exceeding the margin.

Using this method, any level of acceptable error theoretically can be established by increasing the sample size. However, the error quantification is limited to monitored concentration data. Additional error is involved in calculating emission rates using the Gaussian equation or using a mass conservation approach (used for wind tunnel sampling). Quantifying this additional error cannot be assessed specifically, except in modeling validation studies.

EMISSION FACTOR SUMMARY

The following pages present a source-by-source listing of emission factors developed based on the field studies described in the emission factor development section. This list represents a complete summary of emission factors currently in use for mining sources of fugitive dust and fugitive gaseous emissions from blasting and vehicle exhaust. A few emission factors have been intentionally excluded since they did not apply to any specific mining source. Some of the emission factors presented have been superseded by later studies and are no longer used; however, the factors are included for completeness and historical reference.

For the most part, Federal and State permitting agencies have developed lists of preferred emission factors. Of the four states discussed in this report, three (Montana, Colorado, and Wyoming) have specified preferred emission factors for many of the mining dust sources identified here. North Dakota has not specified a preference for any emission factors. EPA, Region VIII, has also developed a list of preferred emission factors which is based loosely on the PedCo, 1978, field study results; these preferences also are indicated in the following summaries. State agencies responsible for preparing preferred emission factor lists are Colorado Department of Health (DH), Wyoming Department of Environmental Quality (WDEQ), and Montana Department of Health and Environmental Science (MDHES).

Several agencies have indicated recently that their preferred lists are likely to change to include the emission factors from the PedCo/MRI 1981 field study (Axetel and Cowherd 1981). Montana already includes those emission factors on their preferred list (MDHES 1982) while Colorado and EPA, Region VIII, are expected to revise their preferred lists shortly. North Dakota is also likely to adopt a preferred list based on the recent PedCo/MRI study.

I. Source: Topsoil Removal

Activity Description: Topsoil is stripped, hauled and placed in storage by scrapers or by a combination of graders, front-end loaders, and haul trucks. Emission factors are based on use of scrapers. Dust results from the scraper wheels and blade and spreading topsoil in the storage area.

Emission Factors	Reference
A. 16 lb/scraper-hour	(PedCo 1976a)
B. 0.38 lb/cubic yard	(PedCo 1978)
C. $(2.7 \times 10^{-5})\ s^{1.3}\ w^{2.4}$ lb/VMT s = Topsoil silt content, (percent 7.2 to 25.2) w = Scraper weight, (tons; 36 to 64) VMT = Vehicle miles traveled	(Axetell and Cowherd 1981)
D. 32 (d/365) lb/scraper-hr d = Number of dry days/yr	(PedCo 1976b)
E. 0.058 lb/ton	(TRC 1981)

Agency Preference:

EPA Region VIII,	A or B
Colorado DH,	A or B
Wyoming DEQ,	D
Montana DHES,	A, B, or C

II. Source: Overburden Removal

Activity Description: Overburden and interbedded waste rock are removed by dragline or shovel. Often scrapers are used to remove the final thin layer over the coal seam. Shovel emission factors include overburden dumping by trucks for consistency with dragline emission factors. Dust results from overburden falling from the dragline bucket or shovel bucket.

Emission Factors	Reference
Removal by Dragline	
A. 0.0056 - 0.053 lb/cubic yard	(PedCo 1978)
B. 0.04 lb/cubic yard	(WDEQ 1979)
C. $0.0021\ d^{1.1}\ M^{-0.3}$ lb/cubic yard	(Axetell and Cowherd 1981)
d = Drop distance (ft; 5 to 100) M = Moisture content (percent; 0.2 to 16.3)	
D. 0.05 lb/ton	(PedCo 1976a)
Removal by Shovel	
E. 0.039 lb/ton	(PedCo 1978)
F. 0.02 lb/ton	(WDEQ 1979)

Removal by Scraper

Emission factors used for overburden removal by scraper are the same as those used for topsoil removal (Section I).

Agency Preference:

EPA Region VIII,	A, E
Colorado DH,	A high end (0.053 lbs/cubic yard), E
Wyoming DEQ,	B, F
Montana DHES,	B or C, F

III. Source: Coal Removal

Activity Description: Coal is removed by shovel or front-end loader and dumped into haul trucks. Dust results from the stream of coal falling from the shovel or front-end loader into the truck.

Emission Factors		Reference
Removal by Shovel.		
A.	0.002 - 0.014 lb/ton	(PedCo 1978)
B.	0.003 lb/ton	(WDEQ 1979)
C.	1.16 $M^{-1.2}$ lb/ton	(Axetell and Cowherd 1981)
	M = Moisture content (percent; 6.6 to 38)	
D.	0.05 lb/ton	(PedCo 1976a)
Removal by Front-End Loader.		
E.	0.12 lb/ton	(PedCo 1978)
F.	0.003 lb/ton	(WDEQ 1979)

Agency Preference

EPA Region VIII,	A, E
Colorado DH,	A-high end (0.014 lb/ton), E
Wyoming DEQ,	B, F
Montana DHES,	B or C, F

IV. Source: Overburden Drilling

Activity Description: Overburden material is drilled at regular intervals and explosives are placed. Dust results from the rock abrasion the drill bit.

Emission Factors	Reference
A. 1.5 lb/hole	(PedCo 1978)
B. 1.3 lb/hole	(Axetell and Cowherd 1981)

Agency Preference

EPA Region VIII,	A
Colorado DH,	A
Wyoming DEQ,	A
Montana DHES,	A or B

V. Source: Coal Drilling

Activity Description: Coal seams are drilled at regular intervals and explosives are placed. Dust results from the coal abrasion by the drill bit.

Emission Factors	Reference
A. 0.22 lb/hole	(PedCo 1978)
B. 1.3 lb/hole	(Axetell and Cowherd 1981)

Agency Preference

EPA Region VIII,	A
Colorado DH,	A
Wyoming DEQ,	A
Montana DHES,	A or B

VI. Source: Overburden Blasting

Activity Description: Overburden material is fragmented by explosives. Dust results from the portion of material that is ejected into the air.

Emission Factors		Reference
A.	14.2 - 85.3 lb/blast	(PedCo 1978)
B.	50 lb/blast	(WDEQ 1979)
C.	0.0026 lb/ton blasted	(CDH 1981)
D.	$961\ A^{0.8}\ D^{-1.8}\ M^{-1.9}$ lb/blast	(Axetell and Cowherd 1981)

A = Area blasted (ft^2; 1,076 to 103,334)
D = Depth of holes (ft; 20 to 135)
M = Moisture content (percent; 7.2 to 38)

E. Gaseous pollutant emission factors for major explosives types used in mines are provided in Table 4 .

Agency Preference

EPA Region VIII,	A
Colorado DH,	C
Wyoming DEQ,	B
Montana DHES,	B or D

TABLE 4. BLASTING GASEOUS EMISSION FACTORS

Explosive	Composition	Carbon Monoxide[a]		Nitrogen Oxides[a]		Methane[b]		Pollu-tant	Other[a]	
		kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton		kg/MT	lb/ton
Dynamite ammonia	20-60% nitroglycerine/ Ammonium nitrate/sodium nitrate/wood pulp	32	63	NA	NA	0.7	1.3	H_2S	16	31
		(23-64)	(46-128)			(0.3-1.1)			(9-19)	(19-37)
Dynamite gelatin	20-100% nitroglycerine	52	104	26	53	0.3	0.7	H_2S	2	4
									(0-3)	(0-6)
		(13-110)	(26-220)	(4-59)	(8-119)	(0.1-0.8)	(0.3-1.7)	SO_2	1	1
									(1-8)	(1-16)
ANFO	Ammonium nitrate with 5.8 to 8% fuel oil	34	67	8	17	NA	NA	SO_2	1	2
									(0-2)	(1-3)

NA = not available.

[a] Based on experiments carried out prior to 1930 except in the case of ANFO.

[b] Factors apply to the chemical species, methane; they do not represent total VOC expressed as methane. Studies were carried out more than 40 years ago.

VII. Source: Coal Blasting

Activity Description: Coal seam is fragmented by explosives. Dust results from the portion of material that is ejected into the air.

	Emission Factors	Reference
A.	25.1 - 78.1 lb/blast	(PedCo 1978)
B.	35 lb/blast	(WDEQ 1979)
C.	0.0026 lb/ton blasted	(CDH 1981)
D.	$961 A^{0.8} D^{-1.8} M^{-1.9}$ lb/blast	(Axetell and Cowherd 1981)

A = Area blasted (ft^2; 1,076 to 103,334)
D = Depth of holes (ft; 20 to 135)
M = Moisture content (percent; 7.2 to 38)

E. Gaseous pollutant emission factors for major explosive types used in mining are the same as those used for overburden blasting (Section VI).

Agency Preference:

EPA Region VIII,	A
Colorado DH,	C
Wyoming DEQ,	B
Montana DHES,	B or D

VIII. Source: Topsoil and Overburden Stockpile Material Handling

Activity Description: Topsoil stockpiles are usually needed for reclamation; however, overburden stockpile use is avoided unless there is a specific reason to store overburden material. In both stockpiles, once the material has been placed, it is usually left undisturbed until needed for reclamation. The material is removed from storage by scrapers or a combination of front-end loaders, dozers, and haul trucks. Dust results from the scraper operations or material loading from front-end loaders to haul trucks.

Emission Factors — Reference

Removal by Scrapers.

A. The factors used for stockpile material removal by scrapers are the same as those used for topsoil removal (Section I).

Removal by Front-End Loaders.

B. 0.037 lb/ton (PedCo 1978)

This factor was calculated for overburden removal by shovel, not front-end loader. (Colorado Department of Health assumes that it also applies to front-end loaders.) (CDH 1981)

Dozer Operations, Overburden.

C. $5.7\ s^{1.2}\ M^{-1.3}$ lb/dozer-hour (Axetell and Cowherd 1981)

s = Silt content (percent; 3.8 to 15.1)
M = Moisture content (percent; 2.2 to 16.8)

Agency Preference.

EPA Region VIII,	None specified
Colorado DH,	B
Wyoming DEQ,	Non specified
Montana DHES,	None specified

IX. Source: Coal Stockpile Material Handling

Activity Description: Crushed coal is usually stockpiled by a conveyor stacker. The coal is removed from the stockpile either by a below-ground reclaimer or by dozers and front-end loaders loading the coal into a reclaim hopper. Dust results from coal falling from the stacker onto the pile and from the reclaimer or front-end loader into the reclaim hopper.

Emission Factors	Reference
Stacker Loading.	
A. 0.0002 lb/ton-throughput	(PedCo 1978)
This factor was developed for a retractable chute loading coal into train cars.	
B. 0.023 lb/ton	(CDH 1981)
This factor was developed for coal conveyor transfer points.	
C. $\frac{0.04\ K_1\ (s/1.5)}{(PE/100)^2}$ lb/ton	(PedCo 1977)
D. $\frac{0.0018\ (s/5)\ (u/5)}{(M/2)^2}$ lb/ton	(MRI 1978)
E. $\frac{0.0018\ (s/5)\ (u/5)\ (H/10)}{(M/2)^2}$ lb/ton	(MRI 1979)
F. $(0.12)\ \frac{0.33}{(PE/100)^2}$ lb/ton-throughput	(EPA 1980)

Variables for C:

K_1 = Activity factor

s = Silt content (percent)

PE = Precipitation-evaporation index

Variables for D:

s = Silt content (percent)

u = Wind speed (mph)

M = Moisture content (percent)

Variables for E:

s = Silt content (percent)

u = Wind speed (mph)

H = Stacker drop height (ft)

M = Moisture content (percent)

Variables for F:

PE = Precipitation-evaporation index

Dozer Operations.

G. $78.4\ s^{1.2}\ M^{-1.3}$ lb/dozer-hour (Axetell and Cowherd 1981)

s = Silt content (percent 6.0 to 11.3)
M = Moisture content (percent 4.0 to 22.0)

H. $\dfrac{0.13\ K_2\ (s/1.5)}{(PE/100)^2}$ lb/ton (PedCo 1977)

K_2 = 0.05
s = Silt content (percent)
PE = Precipitation-evaporation index

This factor is based on "vehicular activity" around sand and gravel piles.

I. $0.10\ K\ (s/1.5)\ (d/235)$ lb/ton (MRI 1978)

K = Activity factor (0.25 for coal)
s = Silt content (percent)
d = dry days/year

This factor is based on "vehicular activity" around sand and gravel piles.

J. $(0.40)\ \dfrac{0.33}{(PE/100)^2}$ lb/ton-throughput (EPA 1980)

PE = Precipitation-evaporation index

This factor is used for "vehicular traffic" on storage piles.

Stockpile Reclaimer.

K. $\dfrac{0.05\ K_3\ (s/1.5)}{(PE/100)^2}$ lb/ton (PedCo 1977)

K_3 = Activity factor
s = Silt content (percent)
PE = Precipitation-evaporation index

L. $$\frac{0.0018\,(s/5)\,(u/5)}{(M/2)^2\,(Y/6)}\ \text{lb/ton} \qquad \text{(MRI 1978)}$$

s = Silt content (percent)
u = Wind speed (mph)
M = Moisture content (percent)
Y = Bucket capacity (yd^3)

This factor is based on batch load-out of coal.

Front-End Loaders.

M. 0.12 lb/ton (PedCo 1978)

N. 0.003 lb/ton (WDEQ 1979)

O. $$(0.15)\ \frac{0.33}{(PE/100)^2}\ \text{lb/ton-throughput} \qquad \text{(EPA 1980)}$$

PE = Precipitation-evaporation index

P. The batch coal load-out equation (emission factor L) can also be used for front-end loaders.

Q. $$\frac{0.04K_4(s/1.5)}{(PE/100)^2} \qquad \text{(PedCo 1977)}$$

K_4 = Activity factor
s = Silt content (percent)
PE = Precipitation-evaporation index

Agency Preference

EPA Region VIII,	A, M, none specified for reclaimer or dozer operations.
Colorado DH,	B, M, none specified for reclaimer or dozer operations.
Wyoming DEQ,	N, none specified for stacker, reclaimer, or dozer operations.
Montana DHES,	A, G, N, none specified for reclaimer operations.

X. Source: Crusher Load-In

Activity Description: Raw coal is dumped from haul trucks into a hopper which feeds a crusher. Dust results from the coal falling into the hopper.

Emission Factors	Reference
Bottom-Dump Truck.	
A. 0.005 - 0.027 lb/ton	(PedCo 1978)
B. 0.017 lb/ton	(WDEQ 1979)
End-Dump Truck.	
C. 0.007 lb/ton	(PedCo 1978)
D. 0.00034 - 0.04 lb/ton	(PedCo 1976a)
Unspecified Vehicle.	
E. 0.066 lb/ton	(TRC 1981)

Agency Preference

EPA Region VIII,	A, C
Colorado DH,	A, C
Wyoming DEQ,	B (for both bottom-dump and end-dump trucks)
Montana DHES,	B (for both bottom-dump and end-dump trucks)

XI. Source: Coal Crushing and Screening

Activity Description: Coal fed into the hopper is crushed by a primary crusher, the coal enters a system of conveyors that feed the coal through secondary and tertiary crushers. The coal is screened and recrushed until reaching a desired size. Dust is emitted by coal fracturing into small particles and from the screening vibration.

Emission Factors	Reference
Primary Crushing.	
A. 0.02 lb/ton	(PedCo 1976a)
Secondary Crushing	
B. 0.06 lb/ton	(PedCo 1976a)
Tertiary Crushing.	
C. 0.18 lb/ton	(CDH 1981)
Secondary Screening.	
D. 0.1 lb/ton	(PedCo 1976a)

Agency Preference

EPA Region VIII,	A, B, D
Colorado DH,	A, B, C, D
Wyoming DEQ,	None specified
Montana DHES,	A, B, D

XII. Source: Conveyors and Conveyor Transfers

Activity Description: Coal is generally conveyed between the primary crusher hopper and the final destination (train loading, power plant, etc.). Dust results from conveyor blowoff and the small drop at each conveyor transfer.

Emission Factors	Reference
A. 0.2 lb/ton Used for all conveyors and conveyor transfers combined.	(PedCo 1976a)
B. 0.023 lb/ton/transfer point	(CDH 1981)

Agency Preference

EPA Region VIII,	A
Colorado DH,	A or B
Wyoming DEQ,	None specified
Montana DHES,	A

XIII. Source: Stockpile Wind Erosion

Activity Description: Topsoil, overburden, and coal stockpiles are assumed to be subject to wind erosion unless completely revegetated. Topsoil and overburden stockpiles that are left undisturbed will show emissions that decrease over time. Coal stockpiles are generally worked on a continuous basis and, therefore, have constant emissions. Dust results from the saltation process, in which larger particles bounce and lift smaller particles into the air.

Emission Factors	Reference
Aggregate Storage Piles (based on sand and gravel).	
A. AIKCLV tons/ac-yr	(PedCo 1976a)

A = Suspended portion (0.025 for rocky, gravelly soil and coal)
I = Erodibility, tons/ac-yr (38 for rocky, gravelly soil and coal)
K = Surface roughness (0.5 to 1.0, use 1.0 for smooth surfaces, coal)
C = Climate factor $= \frac{0.345\ u^3}{(PE)^2}$

u = Wind speed (mph)
PE = Precipitation-evaporation index

L = Field width factor (use 0.7 for 1,000' and 1.0 for 2,000' and greater)
V = Vegetative cover (use 1.0)

B. 0.42 lb/ton in storage - active pile 0.11 lb/ton in storage - inactive pile	(MRI 1974)
C. $(0.33)\ \frac{0.33}{(PE/100)^2}$ lb/ton throughput	(EPA 1980)
D. 0.05 (s/1.5) (D/90) (d/235) (f/15) lb/ton throughput	(MRI 1978)

s = Silt content (percent)
D = Storage duration, days (duration of pile turnover)
d = Dry days/yr
f = Percent of time wind speed exceeds 12 mph

E. 10 lb/ton-yr - fine sand 1.5 lb/ton-yr - crushed rock or gravel	(PedCo 1973)

Coal Storage Piles.

F. $1.6\,u$ lb/ac-hr (PedCo 1978)

u = Wind speed (m/sec)

G. $1.2\,u\,(d/365)$ lb/ac-hr (WDEQ 1979)

u = Wind speed (m/sec)
d = Dry days/year

H. $$\frac{K\,U^3\,\sigma^2\,s^{0.345}}{(PE)^2}\ \text{mg/sec}$$ (Monsanto, 1978)

K = Constant (use 336)
U = Wind speed (m/sec)
σ = Bulk density (gm/cm^3)
S = Pile surface area (m^2)
PE = Precipitation-evaporation index

Agency Preference

EPA Region VIII,	A, F
Colorado DH,	A, with a 5% monthly reduction if stockpile is left undisturbed, for all stockpiles
Wyoming DEQ,	A, G
Montana DHES,	A, G

XIV. Source: Exposed Area Wind Erosion

Activity Description: All ground surfaces in the mine area that have been stripped of vegetation are subject to wind erosion. Dust results from the saltation process in which larger particles bounce and lift smaller particles into the air.

Emission Factors	Reference
A. AIKCLV tons/acre-yr	(PedCo 1976a)

A = Suspended portion (specified below)*
I = Erodibility, tons/ac-yr (specified below)*
K = Surface roughness (0.5 to 1.0, use 1.0 for smooth surfaces)
C = Climate factor $= \dfrac{0.345\ u^3}{(PE)^2}$

u = Wind speed (mph)
PE = Precipitation-evaporation index

L = Field width factor (use 0.7 for 1,000' and 1.0 for 2,000' and greater)
V = Vegetative cover (use 1.0)

*Values for A and I

Surface Soil Type	A	I
Rocky, gravelly	0.025	38
Sandy	0.010	134
Fine	0.041	52
Clay loam	0.025	47

B. $\dfrac{3400\ (e/50)\ (s/15)\ (f/25)}{(PE/50)^2}$ lb/ac-yr (MRI 1978)

e = Erodibility (tons/ac-yr)
s = Silt content (percent)
f = Percent of time that winds exceed 12 mph
PE = Precipitation-evaporation index

C. 0.38 tons/ac-yr (TRC 1981)

This factor was developed for reclaimed land, stripped overburden, and graded overburden using a mean wind speed of 4.7 m/sec.

Agency Preference

EPA Region VIII,	A
Colorado DH,	A
Wyoming DEQ,	A
Montana DHES,	A

XV. Source: Haul Roads

Activity Description: All types of vehicles passing over dirt roads generate dust, which results from lifting material by the vehicle tires and entrainment in the air from the vehicle wake.

Emission Factors	Reference
A. $0.6\ (0.81\ s)\ (S/30)\ (d/365)\ (w/4)$ lb/VMT	(EPA 1980)

s = Silt content (percent)
S = Vehicle speed (mph; $30 < S < 50$)
d = Dry days/yr
w = Number of wheels
VMT = Vehicle miles traveled

Developed for vehicle speeds between 30 and 50 mph

B. $0.6\ (0.81\ s)\ (S/30)^2\ (d/365)\ (w/4)$ lb/VMT	(EPA 1980)

s = Silt content (percent)
S = Vehicle speed (mph; $S < 30$)
d = Dry days/yr
w = Number of wheels
VMT = Vehicle miles traveled
Developed for vehicle speeds below 30 mph.

C. $5.9\ (s/12)\ (S/30)\ (W/3)^{0.8}\ (d/365)$ lb/VMT	(MRI 1978)

s = Silt content (percent)
S = Vehicle speed (mph)
W = Vehicle weight (tons)
d = Dry days/yr

D. $5.9\ (s/12)\ (S/30)\ (W/3)^{0.7}\ (w/4)^{0.5}\ (d/365)$ lb/VMT	(MRI 1978)

s = Silt content (percent)
S = Vehicle speed (mph)
W = Vehicle weight (tons)
w = Number of wheels
d = Dry days/yr

E. $0.16\ (1.068)^S$ lb/VMT	(PedCo 1973)

S = Vehicle speed (mph)
VMT = Vehicle miles traveled

F. $0.0067\ w^{3.4}\ L^{0.2}$ lb/VMT (Axetell, et al, 1981)

w = Number of wheels (6.1 to 10.0)
L = Silt loading,(g/m^2 (3.8 to 254.0)

G. 22.0 lb/VMT (TRC 1981)

This factor was developed for haul trucks averaging 22-24 mph and a road silt content ranging from 8.3 to 11.2%.

Agency Preference

EPA Region VIII,	A, B, or C
Colorado DH,	A, B
Wyoming DEQ,	A, B
Montana DHES,	A, B, or F

XVI. Source: Access Roads

Activity Description: Mine access road traffic includes employee cars and buses, light trucks, maintenance vehicles, and sometimes haul trucks. Access road surfaces range from paved to "chip and seal" to gravel to dirt. In general, emissions are quantified for paved roads or unpaved roads. Dust on unpaved roads results from lifting of material by the vehicle tires and entrainment in the air from the vehicle wake. Dust on paved roads can come from a variety of conditions such as dust or dried mud on the pavement or vehicles or unpaved shoulders.

Emission Factors — Reference

Unpaved Roads

The factors used for unpaved access roads are the same as those used for haul roads (Section XV)

Paved Roads.

A. $0.45 (s/10) (L/5000) (W/3)^{0.8}$ lb/VMT (MRI 1978)

s = Silt content (percent)
L = Dust loading (lb/mile)
W = Vehicle weight (tons)
VMT = Vehicle miles traveled

B. $0.09\ I\ (4/n) (s/10) (L/1000) (W/3)^{0.7}$ lb/VMT (MRI 1979)

I = Industrial road augmentation factor (use 7 if vehicles have traveled over unpaved roads and have dust on underbodies, use 3.5 if road shoulders are unpaved)
n = Number of traffic lanes
s = Silt content (percent)
L = Dust loading (lb/mile)
W = Vehicle weight (tons)

Agency Preference

EPA Region VIII,	Same as haul roads for unpaved; none specified for paved roads
Colorado DH,	Same as haul roads for unpaved; B for paved roads
Wyoming DEQ,	Same as haul roads for unpaved; none specified for paved roads
Montana DHES,	Same as haul roads for unpaved; none specified for paved roads

XVII. Source: Road Maintenance

Activity Description: Dirt and gravel roads are maintained by graders or dozers. Dust results from the blade moving loose material.

	Emission Factors	Reference
A.	32 lb/grader-hour	(PedCo 1976a)
B.	32 lb/dozer-hour	(CDH 1981)
C.	32 (d/365) lb/grader or scraper hour This is presumed to apply also to road construction.	(WDEQ 1979)
D.	$0.04\ S^{2.5}$ lb/VMT	(Axetell and Cowherd 1981)

S = Grader speed (mph; 5.0 to 11.8)
VMT = Vehicle miles traveled

Agency Preference

EPA Region VIII,	A
Colorado DH,	A, B
Wyoming DEQ,	C
Montana DHES,	C or D

XVIII. Source: Railcar Loading

Activity Description: Final crushed coal is loaded into railcars, usually through a telescoping lowering chute. Dust results from the coal falling out of the chute.

Emission Factors	Reference
A. 0.0002 lb/ton	(PedCo 1978)
B. 0.023 lb/ton This was developed for coal conveyor transfer points.	(CDH 1981)
C. $\frac{0.4 K_1 (s/1.5)}{(PE/100)^2}$ lb/ton	(PedCo 1977)

K_1 = Activity factor
s = Silt content (percent)
PE = Precipitation-evaporation index

D. $\frac{0.0018 (s/5) (u/5)}{(M/2)^2}$ lb/ton	(MRI 1978)

s = Silt content (percent)
u = Wind speed (mph)
M = Moisture content (percent)

E. $\frac{0.0018 (s/5) (u/5) (H/10)}{(M/2)^2}$ lb/ton	(MRI 1979)

s = Silt content (percent)
u = Wind speed (mph)
H = Drop height (ft)
M = moisture content (percent)

F. 0.028 lb/ton	(TRC 1981)

Agency Preference

EPA Region VIII,	A
Colorado DH,	B
Wyoming DEQ,	None specified
Montana DHES,	A

XIX. Source: Railcar Blowoff

Activity Description: Loaded train cars are subject to wind erosion, with emissions similar to conveyor blowoff or coal stockpile wind erosion. Dust emissions are generally lower per ton since a smaller surface area is exposed to the wind.

Emission Factors	Reference
A. AIKCLV tons/ac-yr	(PedCo 1976a)

A = Suspended portion (0.025 for coal)
I = Erodibility, tons/ac-yr (38 for coal)
K = Surface roughness (1.0 for coal)
C = Climate factor = $\frac{0.345\ u^3}{(PE)^2}$

u = Wind speed (mph)
PE = Precipitation-evaporation index

L = Field width factor (use 1.0)
V = Vegetative cover (use 1.0)

This was developed foor soil erosion by wind, but it can be used for railcar blowoff.

B. 1.6 u lb/ac-hr	(PedCo 1978)

u = Wind speed (m/sec)

This was developed for coal stockpiles.

C. $\frac{K\ u^3\ \sigma^2\ S^{0.345}}{(PE^2)}$ mg/sec	(Monsanto 1978)

K = Constant (use 336)
u = Wind speed (m/sec)
σ = Bulk density (gm/cm^3)
S = Coal surface area (m^2)
PE = Precipitation-evaporation index

This was developed for coal stockpiles.

Agency Preference

EPA Region VIII,	None specified
Colorado DH,	None specified
Wyoming DEQ,	None specified
Montana DHES,	None specified

XX. Source: Reclamation Grading and Tilling

Activity Description: Once topsoil has been placed on an area to be reclaimed, graders, dozers, or scrapers are used to smooth the surface. The soil is tilled for grass seeding. Dust results from vehicle movement, grading, and tilling.

Emission Factors | Reference

Scraper Operations.

These factors are the same as topsoil removal by scrapers (Section VIII).

Grader and Dozer Operations.

These factors are the same as road maintenance by graders and dozers (Section XVII).

Tilling.

A. $\frac{1.4\ s}{(PE/50)^2}$ lb/ac (EPA 1980)

s = Silt content (percent)
PE = Precipitation-evaporation index

B. $\frac{1.4\ s\ (S/5.5)}{(PE/50)^2}$ (MRI 1974)

s = Silt content (percent)
S = Vehicle speed (mph)
PE = Precipitation-evaporation index

Agency Preference

EPA Region VIII,	None specified for tilling
Colorado DH,	None specified for tilling
Wyoming DEQ,	None specified for tilling
Montana DHES,	None specified for tilling

XXI. Source: Facility Site Construction

Activity Description: When a new mine is constructed, one or more areas of land must be cleared and graded in preparation for facility construction. Site preparation and construction combine many activities including land clearing, ground excavation, grading, vehicle traffic on unpaved areas, and the building construction itself. Emission factors apply to construction activities in general and are usually applicable to building site preparation and construction and road, railroad and pipeline construction.

Emission Factors	Reference
A. 1.2 tons/ac-mo	(MRI 1974)

This factor was developed for construction sites in the desert Southwest (Phoenix and Las Vegas) and includes dust control by watering.

Agency Preference

EPA Region VIII,	None specified
Colorado DH,	None specified
Wyoming DEQ,	None specified
Montana DHES,	None specified

XXII. Source: Equipment Exhaust

Activity Description: All vehicles, diesel or gasoline, emit exhaust pollutants. The major diesel engine pollutants are TSP, SOx, NOx, CO, and VOC. In addition, gasoline engines emit lead (Pb). The TSP emitted by diesel and gasoline engines is much finer than fugitive dust. Approximately 92 percent of diesel exhaust particles and 99 percent of gasoline exhaust particles have diameters less than 1 mm.

Emission Factors	Reference
Major sources of exhaust are listed in the table below.	(EPA 1980)

Equipment Exhaust Sources

	Exhaust Emission Factors (gm/hp-hr)					
Equipment	TSP	SO_x	NO_x	CO	VOC	Pb
Scrapers	0.789	0.901	12.1	2.84	1.22	0
Drills	0.902	0.932	14.8	2.82	1.04	0
Shovels/Dragline	0.805	0.857	11.2	2.62	0.888	0
Front-end Loaders	0.805	0.857	11.2	2.62	0.888	0
Diesel Trucks	0.502	0.887	14.9	2.62	0.853	0
Gasoline Vehicles	3.16	0.130	2.51	76.4	7.50	0.012
Graders/Dozers	0.625	0.874	10.5	2.19	0.489	0
Locomotives	0.644	0.570	3.28	1.60	0.280	0

Agency Preference

EPA Region VIII,	None specified
Colorado DH,	None specified
Wyoming DEQ,	None specified
Montana DHES,	None specified

NORMALIZED EMISSION RATE DEVELOPMENT

Normalized emission rates specify the quantity of fugitive dust produced per million tons of coal mined. Developing of normalized emission rates for each mining dust source provides a means of comparing the relative magnitudes of emissions for each source. It also provides a simple means of calculating an approximate emissions inventory for any particular mine without detailed mine design information. If all emission rates are specified per million tons of coal produced, then a preliminary mine emissions inventory can be calculated merely by knowing the annual production rate at the mine.

Although normalized emission rates are highly desirable for source magnitude comparisons and simple emissions inventories, their development is not straightforward. The emission factors associated with each mine dust source require a variety of mine design parameters, such as overburden volume, haul road vehicle-miles, exposed acreage, etc. Since the values of these parameters vary from mine to mine depending on the design, it is difficult to develop a set of normalized emission rates applicable to all Western surface coal mines.

Despite the fact that mine design data does vary tremendously for Western surface coal mines, much of the variability among mines can be reduced to two key factors: (1) the coal production rate at the mine, and (2) the mine design type. Variability in design parameter values due to coal production rate can be minimized by using normalized data, that is, parameter values per million tons of coal produced. For example, if a 5-million-tpy mine strips 15.0 million bank cubic yards (bcy) of overburden, the normalized overburden volume is 3.0 million bcy. Likewise, much of the design parameter variability is linked to the specific mine design and most surface coal mines can be grouped into a few design types, identifiable by the method of overburden removal.

Since overburden removal is the major mining operation, mine design classifications are based on overburden removal methods. The choice of overburden removal method at a given mine is based on the rate at which overburden must be stripped to achieve the desired coal production level and on overburden thickness. Three primary overburden removal designs are used at Western surface coal mines: (1) by dragline, (2) by shovels loading into trucks, and (3) removal in smaller volumes by a combination scraper and truck/shovel operation.

1. Draglines are generally used only at large production coal mines where large volumes of overburden must be moved. However, dragline removal only involves a strip of land in front of the dragline, so the active mining area is small. Truck traffic around the cut is light since only coal is hauled. Overburden is often handled entirely by the dragline.

2. Truck and shovel operations are normally greater producers of fugitive dust than draglines since the overburden is moved by haul trucks. Overburden is dumped twice, once from the shovel to the truck and once from the truck onto the spoils pile. Truck/shovel mines are generally large open pits with a much greater active area than at dragline mines.

3. Combination scraper/shovel mines are designed for smaller coal production levels. This type of operation is a greater dust producer than strictly shovel operations since scrapers produce more dust per unit volume moved than do shovels and haul trucks.

These three methods of overburden removal provide the means by which coal mines may be grouped. Normalized emissions from mines within each group are roughly equivalent. There are, however, other design differences within each group that can produce further variability in normalized emissions. These include the method of coal removal (shovel or front-end loader), the coal and/or overburden haul truck capacity, the length of haul roads, and the type of equipment used at the coal stockpile. Since these differences have no relation to the mine design type based on overburden removal, they complicate the process of grouping mines into three types. The complications to normalized emission rates caused by these factors are discussed in greater detail in the section on normalized emission rates.

MINE DESIGN DATA

To develop normalized emission rates (per million tons of coal produced), detailed mine operational data were required for each mine design. To satisfy this need, Morrison-Knudsen collected mine design information from three operating Western coal mines representing dragline, truck/shovel, and scraper/shovel operations. Since detailed mine operation data are involved, the three mines are not identified.

The representative dragline mine has a coal production of about 4.4 million tons per year. Coal is removed by a combination of front-end loaders (6 percent) and shovels (94 percent) loading into 150-ton haul trucks. The complete set of mine operation statistics required for dust emission calculations is given in Table 5. A pictorial representation of the mining operation is given in Figure 2.

The representative truck/shovel type operation has a yearly production of about 4.0 million tons of coal. Coal is removed primarily by front-end loaders (90 percent) and shovels (10 percent) and loaded into 50- and 85-ton haul trucks. Overburden is hauled by 120-ton trucks. The area exposed to wind erosion (including pit, spoils, prestripped, facility and reclamation areas) is nearly three times as large as for the dragline operation, at 1,876 acres. Complete design statistics are given in Table 6 while the mining operation is illustrated in Figure 3.

The representative scraper/shovel operation has a yearly coal production that is much smaller the the others at about 0.8 million tons. Overburden is hauled by 24-yd^3 scrapers (47 percent) and 35-, 50-, and 85-ton haul trucks (39 percent). A small portion of the overburden is moved by dozers (14 percent). Coal is removed entirely by front-end loaders and hauled by 40-ton haul trucks. Complete design statistics are given in Table 7.

While the information given for the three mines is representative of their design type, some of the statistics are subject to variability among individual mines. The normalized emission rates calculated from the design data will not

TABLE 5. MINE OPERATION STATISTICS, DRAGLINE MINE

Mine Parameter	Value	Value Per Million Tons of Coal
Topsoil volume stripped	232,060 bcy	52,299 bcy
Overburden drilling rate	16,906 holes/yr	3,810 holes/yr
Overburden blasting rate	200 blasts/yr	*
Overburden removed		
- Scraper	181,400 bcy	40,882 bcy
- Dragline	23,031,700 bcy	5,190,624 bcy
Overburden haul trucks		
- Capacity	Not used	Not used
- Number of wheels	Not used	Not used
- Average speed	Not used	Not used
- Vehicle miles	Not used	Not used
Coal drilling rate	11,475 holes/yr	2,586 holes/yr
Coal blasting rate	200 blasts/yr	*
Coal removed		
- FEL	266,230 t	60,000 t
- Shovel	4,170,944 t	940,000 t
Coal haul trucks		
- Capacity	150 t	*
- Number of wheels	10	*
- Average speed	20 mph	*
- Vehicle miles	64,989 VMT	14,646 VMT
Coal stockpile area	Enclosed stockpile	Enclosed stockpile
Coal stockpile throughput	4,437,174 t	1,000,000 t
Exposed area	639 ac	144 ac
Road grading	2,943 grader-hr	663 grader-hr
Water truck		
- Weight	1 @ 41.5, 1 @ 30 t	*
- Number of wheels	8	*
- Average speed	10 mph	*

TABLE 5. (Continued)

Mine Parameter	Value	Value Per Million Tons of Coal
Water truck - Total miles	27,950 VMT	6,299 VMT
Access road miles	102,200 VMT	23,033 VMT
Railcar, exposed area	0.23 ac each hr	0.05 acres each hr
Total diesel equipment operation	85,000 hr	19,156 hr
Average diesel equipment horsepower	750 hp	*
Total light vehicle operation	61,500 hr	13,860 hr
Average light vehicle horsepower	80 hp	*
Locomotive operation	11,000 hr	2,479 hr
Locomotive horsepower	3,000 hp	*

* Value independent of coal production tonnage.

TABLE 6. MINE OPERATION STATISTICS, TRUCK/SHOVEL MINE

Mine Parameter	Value	Value Per Million Tons of Coal
Topsoil volume stripped	200,000 bcy	49,530 bcy
Overburden drilling rate	24,300 holes/yr	6,018 holes/yr
Overburden blasting rate	200 blasts/yr	*
Overburden removed		
- Scraper	2,633,579 bcy	652,205 bcy
- Shovel	12,238,937 bcy	3,030,968 bcy
Overburden haul trucks		
- Capacity	120 t	*
- Number of wheels	6	*
- Average speed	20 mph	*
- Vehicle miles	382,467 VMT	94,718 VMT
Coal drilling rate	11,000 holes/yr	2,724 holes/yr
Coal blasting rate	200 blasts/yr	*
Coal removed		
- FEL	3,634,167 tons	900,000 t
- Shovel	403,796 tons	100,000 t
Coal haul trucks		
- Capacity	6 @ 50, 6 @ 85 t	*
- Number of wheels	6	*
- Average speed	20 mph	*
- Vehicle miles	385,215 VMT	95,398 VMT
Coal stockpile area	0.5 ac	*
Coal stockpile throughput	403,796 t	100,000 t
Exposed area	1,876 ac	465 ac
Road grading	10,169 grader-hr	2,518 grader-hr
Water truck		
- Weight	1 @ 41.5, 2 @ 12.5 t	*
- Number of wheels	10	*
- Average speed	10 mph	*

TABLE 6. (Continued)

Mine Parameter	Value	Value Per Million Tons of Coal
Water truck, total miles	42,800 VMT	10,600 VMT
Access road miles	490,560 VMT	121,487 VMT
Railcar, exposed area	0.21 ac each hr	0.05 ac each hr
Total diesel equipment operation	250,000 hr	61,912 hr
Average diesel equipment horsepower	650 hp	*
Total light vehicle operation	141,037 hr	34,928 hr
Average light vehicle horsepower	80 hp	*
Locomotive operation	2,020 hr	500 hr
Locomotive horsepower	3,000 hp	*

* Value independent of coal production tonnage.

TABLE 7. MINE OPERATION STATISTICS, SCRAPER/SHOVEL MINE

Mine Parameter	Value	Value Per Million Tons of Coal
Topsoil volume stripped	156,660 bcy	186,536 bcy
Overburden drilling rate	3,664 holes/yr	4,362 holes/yr
Overburden blasting rate	200 blasts/yr	*
Overburden removed		
- Scraper	2,195,080 bcy	2,613,695 bcy
- Dozer	648,266 bcy	771,894 bcy
- Shovel	1,845,273 bcy	2,197,177 bcy
Overburden haul trucks		
- Capacity	1 @ 35, 5 @ 50, 5 @ 85 t	*
- Number of wheels	6	*
- Average speed	20 mph	*
- Vehicle miles	85,827 VMT	102,195 VMT
Coal drilling rate	2,288 holes/yr	2,724 holes/yr
Coal blasting rate	200 blasts/yr	*
Coal tonnage removed		
- FEL	839,838 t	1,000,000 t
Coal haul trucks		
- Capacity	40 t	*
- Number of wheels	16	*
- Average speed	20 mph	*
- Vehicle miles	134,374 VMT	160,000 VMT
Coal stockpile area	0.5 ac	*
Coal stockpile throughput	839,838 t	1,000,000 t
Exposed area	290 ac	345 ac
Road grading	3,978 hr	4,737 hr
Water truck		
- Weight	12.5 t	*
- Number of wheels	10	*
- Average speed	10 mph	*

TABLE 7. (Continued)

Mine Parameter	Value	Value Per Million Tons of Coal
Water truck, total miles	33,810 VMT	40,258 VMT
Access road miles	25,550 VMT	30,423 VMT
Railcar, exposed area	0.04 ac each hr	0.04 ac each hr
Total diesel equipment operation	79,270 hr	94,387 hr
Average diesel equipment horsepower	550 hp	*
Total light vehicle operation	29,630 hr	35,281 hr
Average light vehicle horsepower	80 hp	*
Locomotive operation	1,683 hr	2,004 hr
Locomotive horsepower	3,000 hp	*

* Value independent of coal production tonnage.

apply to every mine of the same design type but are representative of that design type. In some cases, for example, a specific dragline mine may have certain characteristics that are similar to the representative truck/shovel mine; thus, its normalized emissions will be somewhat different than the representative dragline mine. Variances in the normalized emissions for each source due to specific mine characteristics are discussed further below.

NORMALIZED EMISSION RATES

Using the normalized design data given in Tables 5 to 7 and the EPA, Region VIII, preferred list of emission factors as detailed in the emission factor section, normalized emission rates have been calculated for each source of particulate matter at each of the three mines. The results of these calculations are presented in Table 8. The emissions listed in this table provide a method of computing mining fugitive dust emissions for any mine designed similarly to one of the three mine types considered. Since the emissions are normalized, based on mining one million tons of coal per year, actual mine emissions can be computed simply by multiplying by an actual coal production rate factor.

A bar graph representation of the emissions in Table 8 is given as Figure 7; there some of the sources have been combined for simplicity. The emissions given in Table 8 and Figure 7 are uncontrolled emission rates. Dust control strategies for an individual mine must be applied to each source to compute actual emission rates.

Source Comparisons Between Mine Types

Figure 7 graphically points out some important differences between sources at each of the three types of mines. For most sources, the scraper/shovel mine has the highest normalized emissions while the dragline mine has the lowest normalized emissions. The greatest differences in emissions are from haul roads, overburden removal, and road maintenance (road grading and water truck emissions). Differences in normalized emissions for coal removal, equipment exhaust, exposed area wind erosion, access road, reclamation, and coal stockpile handling are significant, but not as great; they are discussed below by source.

Haul Roads

The difference between the mine designs for haul road emissions is caused by two factors: haul truck capacity and number of wheels. Haul truck capacity varies considerably for each mine. The dragline mine uses 150-ton trucks, the truck/shovel mine uses 50- and 85-ton trucks, and the scraper/shovel mine uses 40-ton trucks. Smaller trucks require more trips to haul the same amount of coal, thus producing higher emissions. A similar condition exists for overburden haul emissions. The dragline mine requires no overburden hauling, the truck/shovel mine uses 120-ton haul trucks, and the scraper/shovel mine uses 35-, 50-, and 85-ton haul trucks.

Coal haul truck capacities are not always greater at a dragline type mine than at a truck/shovel mine. The size of the truck has more to do with the mine's coal production level than the mine type. However, it is generally true that

TABLE 8. NORMALIZED FUGITIVE DUST EMISSIONS FOR REPRESENTATIVE SURFACE COAL MINES*

		Normalized Emissions (TPY)		
Source	EPA Emission Factor[a]	Dragline Mine	Truck/Shovel Mine	Scraper/Shovel Mine
Topsoil removal	0.38 lb/yd^3	9.94	9.41	35.44
Overburden removal				
- Scraper	0.38 lb/yd^3	7.77	123.92	643.26
- Shovel	0.039 lb/ton	-	88.66	64.27
- Dragline	0.053 lbs/ton	137.55	-	-
Coal removal				
- Shovel	0.014 lb/ton	6.58	0.70	-
- FEL	0.12 lb/ton	3.60	54.00	60.00
Overburden drilling	1.5 lb/hole	2.86	4.51	3.27
Coal drilling	0.22 lb/hole	0.28	0.30	0.30
Overburden blasting	85.3 lb/blast	8.53	8.53	8.53
Coal blasting	78.1 lb/blast	7.81	7.81	7.81
Stockpile handling				
- Overburden	None	-	-	-
- Topsoil	None	-	-	-
Coal stockpile				
Handling				
- Stacking	0.0002 lb/ton	0.10	0.01	0.10
- Dozer	b	-	25.38	-
- Reclaimer	c	1.00	-	1.00
- FEL	0.12 lb/t	-	6.00	-
Coal crusher load-in	0.007 lbs/ton	3.50	3.50	3.50
Coal crushing				
- Primary	0.02 lb/t	10.00	10.00	10.00
- Secondary	0.06 lb/t	30.00	30.00	30.00
Coal screening	0.1 lb/t	50.00	50.00	50.00
Coal conveying	0.2 lb/t	100.00	100.00	100.00
Coal stockpile wind erosion	d	-	15.66	15.66
Exposed area wind erosion	e	18.72	60.45	44.85
Haul roads				
- Overburden	f	-	160.55	173.22
- Coal	f	41.37	161.70	723.20
Access roads	f	26.03	137.28	34.38
Road maintenance				
- Grading	32 lb/hr	10.61	40.29	75.79
- Water truck	f	14.24	29.95	113.73
Railcar loading	0.0002 lb/t	0.10	0.10	0.10
Railcar blowoff	d	1.57	1.57	1.25
Reclamation				
- Grader	32 lb/hr	2.53	5.34	4.00
- Tilling	g	1.60	3.37	2.52

TABLE 8. (Continued)

Source	EPA Emission Factor[a]	Normalized Emissions (TPY)		
		Dragline Mine	Truck/Shovel Mine	Scraper/Shovel Mine
Facility site construction	none	-	-	-
Equipment exhaust				
- Diesel	h	10.35	29.01	37.42
- Light	h	3.86	9.73	9.83
TOTAL		510.50	1177.73	2253.43

* Emissions are based on EPA Region VIII emission factors and are normalized for a 1-million tpy coal production.

[a] EPA does not specify an emission factor for each source listed. Those emission factors used that are not on the EPA preferred list are given in parentheses.

[b] Emmission Factor $= (0.4) \dfrac{0.33}{(PE/100)^2}$ lb/ton-throughput

where: PE = Precipitation-evaporation index

[c] Emmission Factor $= \dfrac{0.0018\ (s/5)\ (u/5)}{(M/2)^2\ (Y/6)}$ lb/ton-throughput

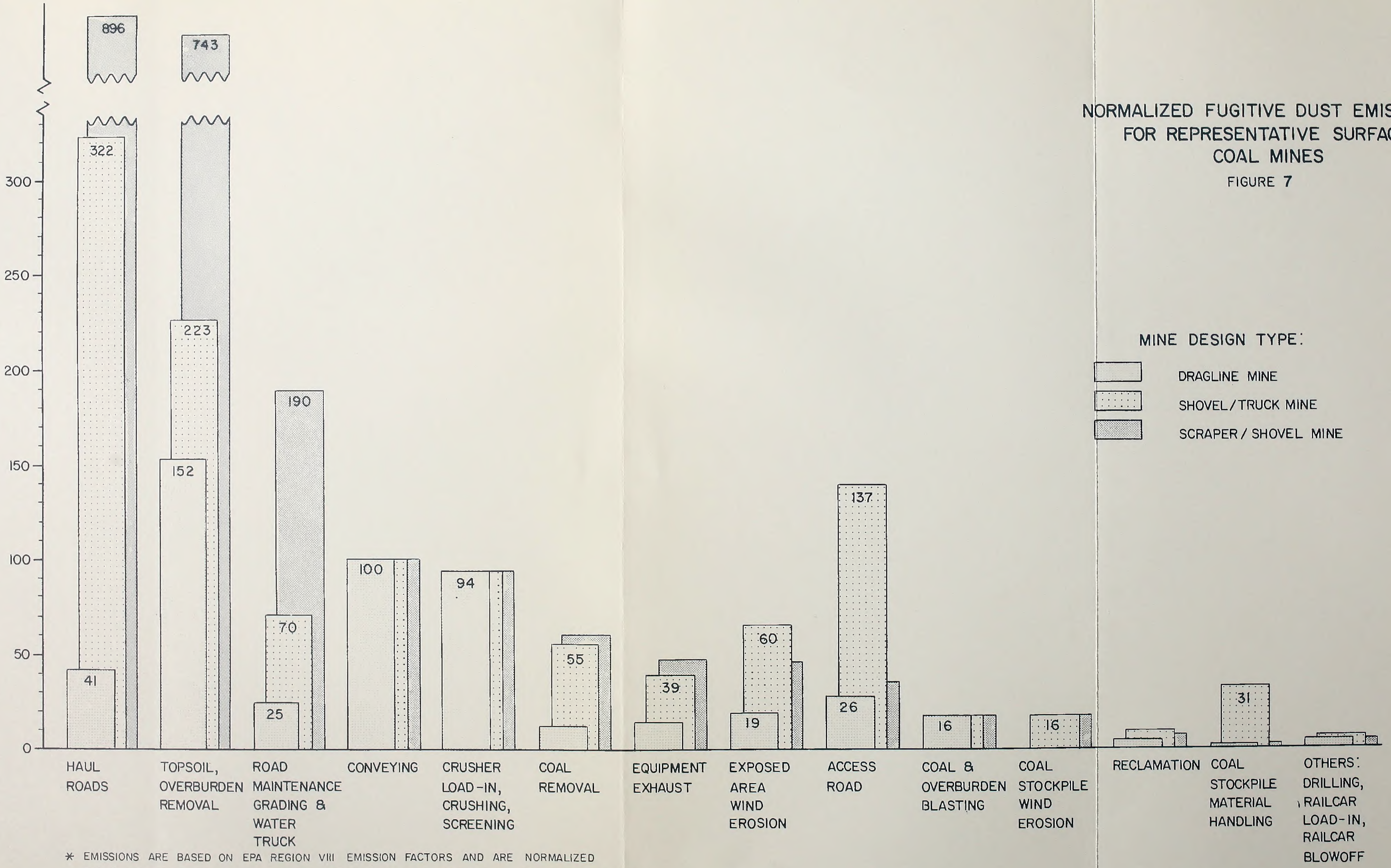
where:
s = Silt content (%)
u = Wind speed (mph)
M = Moisture content (%)
Y = Bucket capacity (yd^3)

Using standard values and a 2-yd^3 bucket gives EF = 0.002 lb/ton-throughput

[d] Emmission Factor = 1.6 u lb/ac-hr

where: u = Wind speed (m/sec)

Using u = 4.47 m/s (10 mph) gives EF = 7.15 lb/ac-hr



NORMALIZED FUGITIVE DUST EMISSIONS
FOR REPRESENTATIVE SURFACE
COAL MINES

FIGURE 7

* EMISSIONS ARE BASED ON EPA REGION VIII EMISSION FACTORS AND ARE NORMALIZED FOR A 1,000,000 TON PER YEAR COAL PRODUCTION. SEE TABLE 5-4 FOR COMPLETE DATA.

TABLE 8. (Continued)

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[e] Emmission Factor = AIKCLV ton/ac-yr

where all variables are identified in the emission factory summary section. Using standard values, EF = 0.13 ton/ac-yr.

[f] Emmission Factor $= 0.6\ (0.81\ s)\ (S/30)\ (d/365)\ (w/4)$ lb/VMT for $30 < S < 50$
$= 0.6\ (0.81\ s)\ (S/30)^2\ (d/365)\ (W/4)$ lb/VMT for $S < 30$

where:
s = Silt content (%)
S = Vehicle speed (mph)
d = Dry days/year
w = Number of wheels

Standard values used are s = 15%, S = 20 mph, d = 255. Value for w depends on truck.

[g] Emmission Factor $= \dfrac{1.4\ s}{(PE/50)^2}$ lb/ac

where:
s = Silt content (%)
PE = Precipitation-evaporation index

Standard values gives 20.19 lb/ac

[h] See table, Section XXII. For simplicity, the mix of diesel vehicles is represented by the average TSP exhaust emission factors for shovels/dragline and diesel trucks (a value of 0.654 gm/hp-hr). The mix of light vehicles is represented by the TSP exhaust emission factor for gasoline vehicles (3.16 gm/hp-hr).

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coal haul truck capacities as well as overburden truck capacities at scraper/shovel mines are smaller since these mines generally operate at smaller coal production levels.

The other factor affecting haul road emissions, the number of wheels on the haul trucks, is mostly a matter of truck design, and causes some emissions variability from mine to mine.

Also, haul road emissions vary by the length of the road. The emissions from the dragline mine are low in part because the average haul road length is about 1 mile; whereas, the average road length is about 3 miles at the two other representative mines.

Topsoil and Overburden Removal

The overburden removal emission difference is caused mostly by the method of removal; scrapers produce more dust than shovels and shovels produce more dust than draglines per unit of overburden moved. Some variability in the emissions is introduced by the mine's stripping ratio. The representative scraper/shovel mine happens to have the highest stripping ratio at 5.6 bcy/ton (the truck/shovel mine is 3.7 and the dragline mine is 5.2). The difference in topsoil removal emissions is mostly due to differences in coal seam thicknesses. Mines with these coal seams involve larger areas of topsoil removal per million tons of coal removed.

Road Maintenance

The difference in normalized emissions from road maintenance for the three mine designs is caused by several factors, the most important of which is the volume of traffic on the haul roads. Road grading and water truck requirements tend to be proportional to haul road traffic, illustrated in Figure 7. Other factors producing the differences between the mines are length of haul roads and other access roads, climate, and regulatory commitment to dust control by water trucks; these factors introduce considerable variability between mines.

Coal Removal

Normalized emissions for coal removal also show differences for each mine design type. The difference is directly related to the proportion of front-end loaders to shovels. Front-end loaders produce more dust per unit of coal loaded than do shovels. Thus, the dragline mine, which loads 96 percent of the coal by shovel, has the lowest normalized emission rate. The truck/shovel mine and the shovel/scraper mine, which use front-end loaders for 90 percent and 100 percent of coal loading, respectively, have much higher normalized emission rates.

Equipment Exhaust

Normalized emissions for equipment exhaust reflect the use of smaller vehicles at the scraper/shovel mine and larger vehicles at the dragline mine. The scraper/shovel mine has the highest normalized emission rate since more vehicles are required to move the same amount of coal or overburden.

Exposed Area, Access Road, and Reclamation

Three sources are related directly to the physical size of the mine operation and their normalized emission rates show the same pattern at each mine: (1) exposed area wind erosion, (2) access road traffic, and (3) reclamation area emissions. For each source the truck/shovel mine has the highest emissions and the dragline mine has the lowest. Truck/shovel mines operate in huge open pits and require large areas of active mining, which in turn implies more access roads and larger reclamation areas for a given production rate. On the other hand, dragline operations require only a small cut to be active at any time. Thus, even after active mining areas are normalized for a 1-mmtpy operation, the truck/shovel operation has the largest mine area simply due to the mine design.

Coal Stockpile Handing

Normalized emission rates for coal stockpile material handling show a large difference for the truck/shovel mine due to the equipment used to reclaim coal from the pile. The other two mines both use continuous underground reclaimers, but coal from the truck/shovel mine stockpile is loaded out by dozers and front-end loaders. The emissions from this equipment are much higher per unit of coal reclaimed.

The other sources of particulate matter given in Table 8 and Figure 7 show little or no difference among the mine designs.

Summary

The normalized emission rates given in Table 8 and Figure 7 can be used to give an approximate mining emissions inventory for any mine, using only the coal production rate for that mine. The emission rates are given for the three mine designs most commonly found at western surface coal mines. The calculations are made using data from actual operating coal mines considered to represent each category. Emissions from any specific coal mine are likely to be very similar to the representative mine, although certain design variations may require special attention. In summary, when estimating actual mine emissions for a particular mine of one of the three types considered, the following points should be considered:

1. The normalized emissions presented in this section are based on a given set of emission factors. Use of the other emission factors will result in changes to the calculated emissions. Other emission factors may be more appropriate to specific situations.

2. Emissions presented in this section do not reflect the application of dust control methods used at most mines. Calculated emissions should be adjusted to reflect the application of controls before ambient impacts of mining operations are estimated.

3. Normalized emission rates for haul roads and road maintenance are more closely related to haul truck capacities and road traffic volumes than to any particular mine design type. If specific information about

truck capacities and road traffic is available, a more accurate emission estimate is obtained by using the specific mine design information.

4. While normalized emissions from overburden removal are well correlated to the mine design type, they also vary according to the stripping ratio. The stripping ratios for the mines presented are 5.2 bank cubic yards per ton (bcy/ton) for the dragline, 3.7 bcy/ton for the truck/shovel, and 5.6 bcy/ton for the scraper/shovel mine. If the stripping ratio for a particular mine is known, an adjustment to the overburden removal emissions should be made.

5. Normalized emission rates for coal removal are more closely related to removal equipment type than mine design type. Equipment used at each representative mine is as follows:

	Dragline	Truck/ Shovel	Scraper/ Shovel
Shovels	96%	10%	0%
Front-end loaders	4%	90%	100%

   If specific information on coal removal equipment is known for a particular mine, the normalized emission rate used should be the one that represents the specific mine equipment.

6. Equipment exhaust emissions are somewhat related to truck capacity since use of smaller trucks requires a larger fleet to move the same amount of coal or overburden. The choice of the normalized emission factor for equipment exhaust should be for the same mine type as used for haul road emissions.

7. Stockpile material-handling emissions are highly dependent on the type of reclaiming equipment used. If a below-ground continuous reclaimer is used, the emissions are very small. If front-end loaders and dozers are used, the emissions are much higher.

Although the information given in Table 8 and Figure 7 is useful in determining an estimate of emission for any specific surface coal mine, a detailed emission inventory using specific mine design data is required for air quality permitting purposes. When an inventory using detailed data is required, a consultant familiar with mining emissions analysis is essential.

AIR QUALITY IMPACTS

Air quality impacts from surface mining operations are discussed in terms of ambient air concentrations of the pollutants emitted from sources at the mine. Ambient air concentrations are simply the amount of pollutant measured in the air at some point away from the mine. These measurements include both mine impacts and "background" pollutant levels. Measurements are commonly in units of micrograms per cubic meter ($\mu g/m^3$).

Direct measurement of pollutant concentrations can be done at operating mines but is, of course, impossible for a proposed coal mine. However, air quality regulations require that ambient air concentrations be estimated for any proposed mine, thus a method is needed to calculate the concentrations based on mine emissions and dispersion characteristics of the atmosphere. Computer models that simulate mine emissions dispersing in the atmosphere are used to make these calculations.

Modeling Methodologies

"Modeling" is a term used to describe the process of calculating projected air quality impacts by means of computer programs which use mathematical equations describing the transport and diffusion of materials in the atmosphere. The locations and rates of emission of all the sources at the mine; the source characteristics such as exhaust speed, temperature of the pollutant, and release height; and the atmospheric turbulence which disperses the plume (e.g., dust cloud) are considered in calculating the predicted ambient concentrations. A variety of computer codes embodying these relationships is available -- some considering sophisticated chemical interactions and particulate deposition in windfields which vary in strength and direction with time, others simplistically assuming a fixed dispersion through an angular sector away from the source. Varying terrain and multiple atmospheric layers with varying meteorological conditions (including wind direction) are available. The accuracy with which a model approximates the conditions of the actual atmosphere is determined by its complexity in terms of realism and its flexibility and range of calculating equations. The more simplistic models make coarse assumptions and generalizations which are "conservative," that is, they tend to overestimate predicted concentrations. Simplistic or complex, any model's accuracy is bounded by the technical accuracy of its calculations and by the quality of the meteorological and source emissions data used as input.

The choice of which model to use and the methodology by which it is applied are key decisions upon which the success of the entire permitting effort depends. Permitting agencies require the use of agency-approved computer models in making impact assessments presented in any permit application. Generally, the agency staff independently analyzes the proposed operation using data provided by the applicant and compares the projected impacts they calculate with those presented in the permit application. The impacts assessment should be coordinated with the agency from the most early stages of the permit preparation to assure a mutually acceptable result and a most cost-effective analysis.

Model Features

Dozens of models potentially usable in the air quality permitting analysis for surface mines are available from various sources. Many are proprietory programs, copyrighted by consulting firms, with special features unique to a given consultant. Table 9 which summarizes the characteristics of air quality models available from EPA, reveals several important and varying capabilities of the models. The time scales over which the model predicts concentrations vary from model to model. The time scale used in permitting analysis must match the time

TABLE 9. AIR QUALITY MODEL SUMMARY

Model	Time Scale	No. of Sources	Source Types	No. of Recep.	Fixed Recep. Grid?	Pollutant Decay	Length Scale	Met. Data	Plume Rise	Horizontal Dispersion	Terrain	Source Contribution Breakdown?	Special Abilities or Limitations
APRAC-1	1 hr-annual	Unlimited	Line	625	No	No	1-50	Hourly km	No	Gaussian	No	No	Carbon monoxide in an urban environment. Street canyon diffusion.
CDM	24 hr-annual	200 2,500	Point area	Unlimited	No	Exp.	100 m-50 km	JFF	Briggs/final	Gaussian	No	No	2 pollutants in one run.
CDMQC	24 hr-annual	200 2,500	Point area	200	No	Exp.	100 m-50 km	JFF	Briggs/final	Gaussian	No	Yes	Internal calibration, individual source contributions, Larsen's transform from annual.
CRSTER	3 hr-annual	1	Point	180	Yes	No	100 m-inf.	Hourly	Briggs	Gaussian	Partial	N/A	Urban/rural option.
HIWAY	1-24 hr	Unlimited	Area line	Unlimited	No	No	Short	Hourly	No	Gaussian	No	No	
PAL	1-24 hr	30 30	Point area	30	No	No	10-1,000 m	Hourly	Briggs/final	Gaussian	No	No	Point source integration to produce line source, vertical wind shear.
PTMAX-PTDIS	Less than 1 hr	1	Point	N/A	N/A	No	Short	Hourly	Briggs	Gaussian	No	N/A	
PTMTP	1-24 hr	25	Point	30	No	No	100 m-100 km	Hourly	Briggs	Gaussian	No	Yes	
RAM	1-24 hr	Unlimited	Point area	Unlimited	No	Exp.	Short	Hourly	Briggs	Gaussian	No	Yes	Receptor grid options. RAMF, RAMFR - Annual.
VALLEY	24 hr-annual	50	Point area	112	Yes	Exp.	100 m-inf.	JFF	Briggs/final	Sector average	Yes	Yes	Fumigation, scaled map output, urban/rural option.
BLP	1 hr-annual	50 10	Point line	100	Optional	Linear	100 m-inf.	Hourly	Shear/downwash	Gaussian	Yes	Yes	Plume rise for multiple line sources, building downwash, vertical wind shear.
COMPLEX I[a]								Hourly		Sector average	Yes		
COMPLEX II[a]	1 hr-annual	250	Point	180	Optional	Exp.		Hourly	Briggs/final	Gaussian	Yes	Yes	Vertical wind profile, 2 pollutants in one run.
HIWAY-2	1 hr	Unlimited	Area line	50	No	No	10-1,000 m	Hourly	No	Gaussian	No	No	Atmospheric drag coefficient for low wind speeds.

TABLE 9. (Continued)

Model	Time Scale	No. of Sources	Source Types	No. of Recep.	Fixed Recep. Grid?	Pollutant Decay	Length Scale	Met. Data	Plume Rise	Horizontal Dispersion	Terrain	Source Contribution Breakdown?	Special Abilities or Limitations
ISCLT	Annual	Unlimited	Point area line	Unlimited	Optional	Exp.	100 m -inf.	JFF	Briggs	Sector average	Partial	No	Vertical wind profiles and temperature gradients stack downwash, building wakes, dry deposition, urban/rural option, variable emission rates.
ISCST	1-24 hr	Unlimited	Point area	Unlimited	Optional	Exp.	100 m -inf.	Hourly	Briggs	Gaussian	Partial	No	
MPTER	1 hr-annual	250	Point	180	Optional	Exp.	100 m-100 km	Hourly	Briggs/final	Gaussian	Yes	Yes	Stack downwash, vertical wind profiles, output processing.
PTPLU*	1 hr	1	Point					Hourly	Briggs	Gaussian	No	N/A	Vertical wind profile, stack downwash.
TCM	Seasonal-annual	Unlimited	Point area	2,500	Yes	Exp.	100 m -60 km	JFF	Briggs/final	Gaussian	No	Yes	Fast computation, 2 pollutants urban option.
TEM	10 min-24 hr	300 50	Point area	2,500	Yes	Exp.	100 m -60 km	Hourly	Briggs	Gaussian	No	Yes	Fast computation, stack downwash.
CDM-WYOMING	24 hr-annual	200 10,000	Point Area	Unlimited	No	Exp.	100 m-50 km	JFF	Briggs/final	Gaussian	No	No	Wyoming stations JFF.
IMPACT	1-3 hr	50 50	Point Area	40x40 x20	Yes	Chem. Models	500 m -40 km	Hourly	Briggs/TVA/final	Stepped Advect.-Diffus.	Yes	No	Arbitrary vertical temperature profile, 3-D wind and diffusion fields, chemical transformations, background concentrations
MILDOS	Annual	20	Point Area	48	No	Exp.	100 m -80 km	JFF	Briggs	Sector average	Partial	Yes	Particle deposition and re-suspension, radiation dose pathways, variable emission rates.
PLUVUE	Instantaneous	1	Point	16	No	Chem. Model	100 m -50 km	Instantaneous	Briggs	Gaussian	No	N/A	Visual range, plume/background contrast, plume color shift, deposition, vertical wind profile, optics.

* No user's Manual. Certain model characteristics could not be determined due to lack of information.

frame of the regulatory standard; particulates, for instance, have both annual and 24-hour standards. Also, models vary in the number of geographically distributed sources they will accept. Surface mines (as opposed to power plants, for example) are characterized by large numbers of sources distributed across varying terrain and, therefore, some models are more suitable than others.

Models mathematically approximate pollutant sources according to their geometry. Surface mines often have several sources of each of the following types:

-- Point Sources - Single emitting locations (stacks, baghouse exhausts, etc.)
-- Line Sources - Haul roads and other sources occurring in a defined path
-- Area Sources - Activities occurring over a broad area (scraper and dragline operations)

The locations at which ambient concentrations are calculated are called receptors. Agency evaluations require a dense enough receptor array to locate and quantify the point of maximum concentration. Computer time (and associated cost) required to make the calculations increase dramatically with the increase in receptors specified. Therefore, judicious selection and spacing of receptors are important economic considerations. Some models are inflexible in the geographical arrangement of their receptor grid. This constraint becomes important if evaluating a geographically diverse operation.

Another consideration in evaluating computer models is that many of them have pollutant decay provisions of varying complexities. Use of this feature may enable a more accurate assessment of dust deposition effects, for example, but the methodology must be sanctioned by the agency if the results are to be accepted. Downwind distance capabilities are usually not of great concern in modeling surface mines, but calculations of up to 50 km downwind are sometimes necessary in PSD evaluations of Class I areas. However, steady-state Gaussian models will calculate theoretical concentrations at infinite distances. Therefore, care must be taken that unrealistic receptor placement is not made.

Meteorological data used in the modeling must coincide with the time frame evaluated. Annual average calculations may utilize a joint frequency function to describe the annual meteorology for the model. Short-term models, or those calculating sequential concentrations over time, require a sequential meteorological data set by which the worst case meteorology or sequential scenario may be determined.

Most models make assumptions that characterize the horizontal and vertical dispersion of the material as it moves downwind. Generally, horizontal and vertical dispersion of the pollutant is assumed to form a Gaussian plume; however, some models use a sector averaging approach for horizontal dispersion (as described in the section under air quality explaining model assumptions).

Capabilities for incorporating terrain in the assessment are available. Their usefulness is determined by needs for considering the terrain of the site investigated. Terrain effects specific to mine pits are not considered by any of the models listed in Table 9.

Available Models

There are four basic types of models which may be applicable to mining air quality analyses: (1) box, (2) steady-state Gaussian, (3) trajectory, and (4) grid models.

The accuracy of these model types covers a broad spectrum, so applicability depends on the specific situation. Generally, the appropriateness of any model type is dependent on the type and extent of the available input data based on negotiations with the permitting agency.

A brief discussion of each model type, potential applications, and the required data type is presented below.

Box Models

Box models are generally applied in topographic and emission situations where it can be assumed that emissions are uniformly mixed throughout a volume of air. An urban area located in a valley would be a good example. A box model could also be applied in a steep-walled canyon where winds persist in one direction much of the time. Because the box model concept assumes uniform pollutant mixing, box models are generally used to calculate long-term average concentrations. The shortest averaging time is usually 24 hours.

The data requirements for box models are very rudimentary. Climatological averages of wind speed and mixing height are the only meteorology requirements, while only gross project emission rates are required as emissions input. The spatial distribution of emissions is not important.

The accuracy of box models is consistent with the input data. The user should consider the results of a box model as a "first-cut" estimate of actual ambient concentrations.

Gaussian Models

Gaussian models were originally designed to calculate ambient concentrations within tens of kilometers of a source located in flat terrain. A basic assumption of this model type is that meteorological conditions are assumed to persist during the averaging period. Therefore, the model assumes that a plume will travel in a straight line, at a constant wind speed, and under constant atmospheric stability conditions. One can carry this concept to the extreme and calculate theoretical impacts hundreds of kilometers from a source; this assumption can also lead to serious errors in cases where meteorological conditions are highly variable or influenced by topography.

Gaussian models are most often used in situations when pollutants are not chemically reactive and do not settle to the ground. However, the basic concepts have been modified to include chemical transformation plume deformation due to topography and deposition velocities as pollutant removal mechanisms. These and other adaptations have improved the accuracy of the models in many applications.

Advantages of Gaussian models include:

- Short- or long-term concentrations
- Models used with limited meteorological data
- Modeling of isolated or many sources
- Relatively inexpensive model runs
- Easy-to-understand model algorithms
- Easy-to-use models

Disadvantages of the Gaussian model include:

- Calculation of concentrations at unreasonable distances or locations
- Application of flat terrain assumptions in complex terrain
- Steady-State meteorology assumption

Although some drawbacks exist, most of the commonly used mining evaluation models are of the Gaussian type.

Trajectory Models

Trajectory models allow analysis of a parcel of air or plume element following wind meanderings . The plume elements may diffuse in a Gaussian manner or may be assigned specific geometry (i.e., a box) and air may be exchanged in and out. In any event, the meteorological requirements are generally more extensive than those of Gaussian models. To define the trajectory, data from a number of wind monitors are generally required.

Trajectory models are most useful in areas where meteorological conditions are highly variable (e.g., seashore and mountain-valley situations). Model results are limited since concentrations are calculated only along a specific path, which precludes concentration analysis over an area unless those concentrations are figured along several trajectories, which can be expensive. Trajectory models are sometimes necessary to address air quality and visibility impacts in cases where a proposed large mining operation is adjacent or upwind to national parks or wilderness areas.

Grid Models

Grid models are perhaps the most complex models available to air quality specialists. Meteorological, air quality, and emissions data requirements are extensive, but model results generally correlate very well with observed pollutant concentrations.

Grid models are based on a fixed coordinate system with the area of interest divided into an array of grid cells (cells may be stacked on top of each other so that the array is three dimensional). A detailed emissions inventory is required with emissions assigned to the appropriate grid cell. Pollutant concentrations in each cell are calculated based on the following process:

- Air/pollutant transport into the cell
- Pollutant addition due to sources

-- Pollutant losses due to diffusion into neighboring cells
-- Pollutant losses due to chemical reactions
-- Pollutant losses due to deposition

Grid model data requirements include:

-- Wind field variation over space and time
-- A gridded emissions inventory
-- Measurements of vertical turbulence and thermal characteristics of the atmosphere
-- Deposition rates of particles and/or gases
-- Rates of chemical reactions (for photochemical models)

Grid models, generally only applied in the most adverse mine permitting environments, are very expensive to set up and run and are proprietory to the consultant in most cases. The results are generally applicable to averaging times of up to a few days. Grid models are .

Model Selection Criteria

Purpose of Modeling

Mathematical modeling is undertaken to achieve three objectives in the permitting scheme. (1) Models may be used to grossly estimate facility impacts and determine the applicability of regulation, which activity is referred to as "screening modeling"; and is commonly undertaken to determine whether monitoring is required.

(2) Modeling also is used as a tool to predict the locations of maximum concentrations of pollutants from the proposed facility in conjunction with adjacent, nonproject sources. Once the locations of predicted maximum impacts are identified, monitoring equipment (often an agency requirement) is installed at those locations so that there is data from before and after project impacts. (3) Finally and most significantly, models are used to estimate whether the proposed location and design of the facility will result in a violation of any air quality standard. In this assessment, modeling must be considered only a subcomponent of the more comprehensive analyses which include the total facilities design and Best Available Control Technology (BACT) analysis.

Source Configuration and Receptor Siting

The spatial arrangement necessary to portray a given mining operation as an arrangement of point, line, and area sources is best decided by a modeling consultant after considering the characteristics of the mine plant and modeling technique, along with the requirements of the permitting agency. Similarly, improper positioning of receptors relative to sources may fail to account for physical assumptions inherent in the model equations and lead to erroneous results. Likewise, a superficial receptor siting or density may lead to a violation which when detected by the agency may necessitate another analysis.

Averaging Time: Annual Versus Short-Term

Because TSP ambient air quality standards for particulates are framed in annual and 24-hour time periods, agencies generally require discrete modeling runs which individually address these time frames. Average annual calculations are readily calculated using total tons-per-year emissions from each of the sources and an annual joint frequency distribution of the salient meteorological factors. For a surface mine, representative 24-hour worst-case projections are much more difficult to formulate, because unlike an industrial stack, the mine operations are not constant over periods of several days. Many of the emission factors (source strengths) are dependent on meteorological conditions, and the worst-case emissions (in terms of sources operating and source strength) may not occur during the worst-case meteorological conditions. More sophisticated joint analyses are possible, but such effort seems ineffective when often only one year of on-site data is available and when the long-term representativeness of that data is questionable. Some agencies recognize the problems inherent in this analysis.

Model Assumptions and Limitations

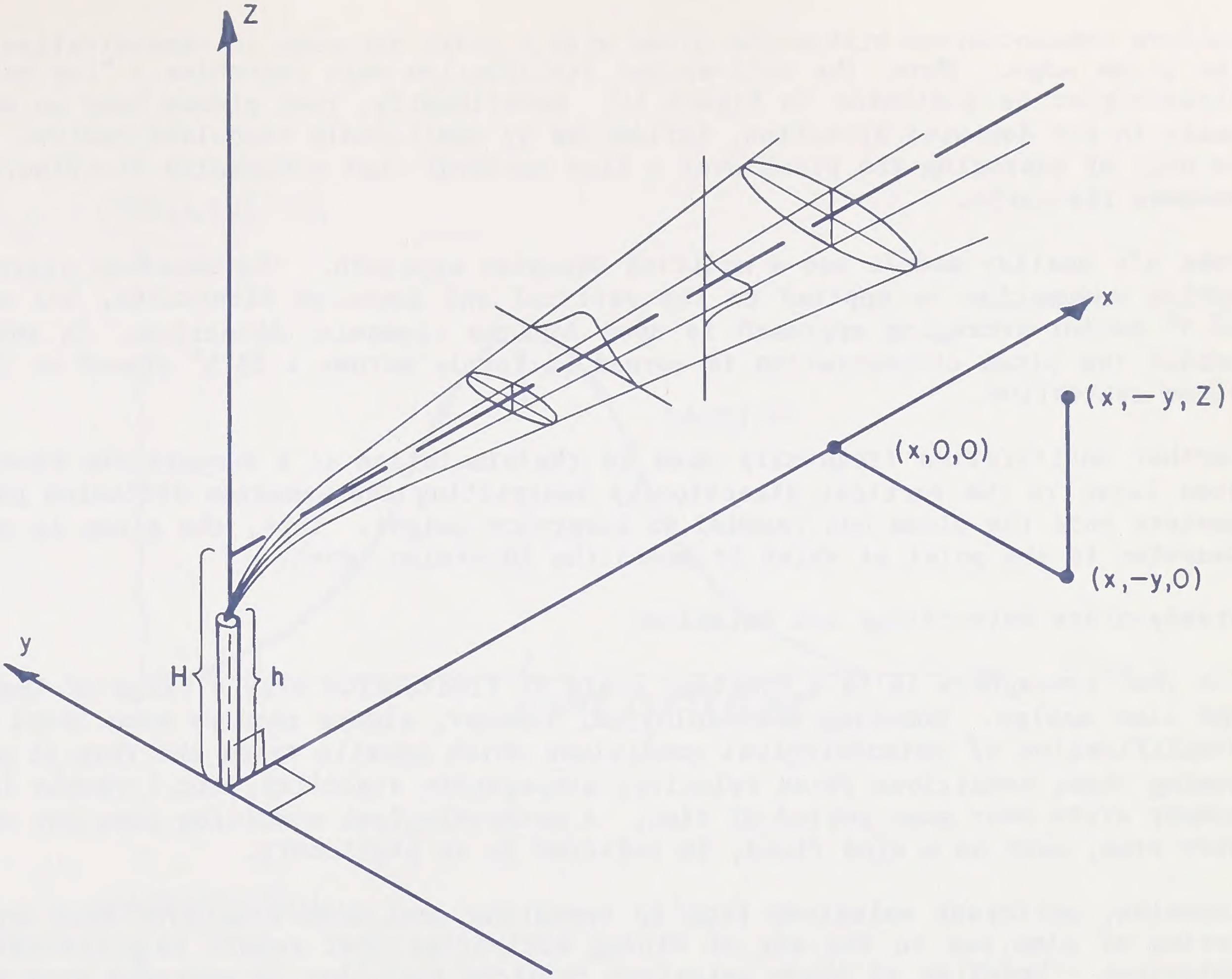
Since no computer simulation can exactly represent actual physical conditions for a medium as complex as the atmosphere, all dispersion models must make assumptions to simplify complexities to manageable form. In most cases model assumptions follow established atmospheric theory and observation and are intended to represent atmospheric or pollutant emission conditions as realistically as possible. In some models assumptions are intentionally conservative, leading to the moderate results usually desired in air quality permitting applications.

There are as many model assumptions and limitations as there are models; the ones used in mine applications are described below.

Gaussian Distribution

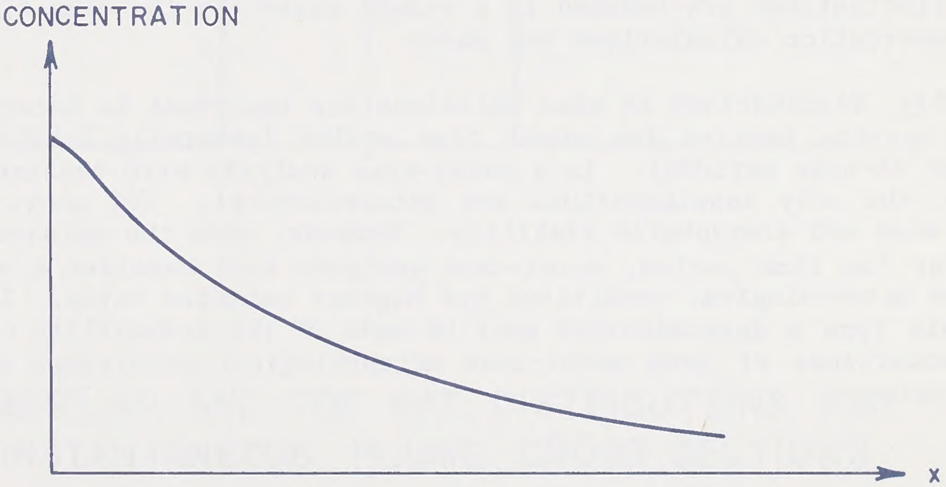
Most air quality dispersion models used for mine emission modeling are of the Gaussian type; they use a common assumption that pollutants emitted from a source form a time-averaged plume in the downwind direction in which pollutant concentrations decrease exponentially away from the plume centerline and away from the source. That is, a cross section of the plume would show the highest concentrations at the center, decreasing exponentially in all directions away from the center. Likewise, concentration measurements taken at the plume centerline at various distances downwind of the source would show an exponential decrease with distance. These relationships are illustrated in Figures 8 and 9. In both figures, plots of concentration versus distance take the form of the "bell" curve representing a statistically normal distribution. The shape of the bell indicates the rate at which concentrations decrease, which is quite different for the vertical (Z), crosswind (y), and downwind (x) directions.

The Gaussian distribution assumption has only limited application, particularly for instantaneous simulations of real plumes since it is a time-averaged concept. Concentration distributions measured in actual plumes exhibit a more



GAUSSIAN DISTRIBUTION PLUME FOR A SINGLE POINT SOURCE (Redrafted from Turner, 1970)

FIGURE 8



GAUSSIAN DISTRIBUTION FOR DISTANCE DOWNWIND

FIGURE 9

uniform concentration within the plume with a sharp decrease in concentration at the plume edge. Thus, the bell-shaped distribution more resembles a "top hat" distribution as indicated in Figure 10. Additionally, real plumes tend to meander in the downwind direction, influenced by small-scale turbulant eddies. It is only by averaging the plume over a time interval that a Gaussian distribution becomes realistic.

Some air quality models use a modified Gaussian approach. The Gaussian distribution assumption is applied to the vertical and downwind directions, but a 22.5° sector-averaging approach is used for the crosswind direction. In this method the plume concentration is spread uniformly across a 22.5° around on the plume centerline.

Another modification frequently used is the simulation of a temperature inversion layer in the vertical direction by restricting the Gaussian diffusion parameters once the plume has reached an inversion height. Thus, the plume is only Gaussian to the point at which it meets the inversion level.

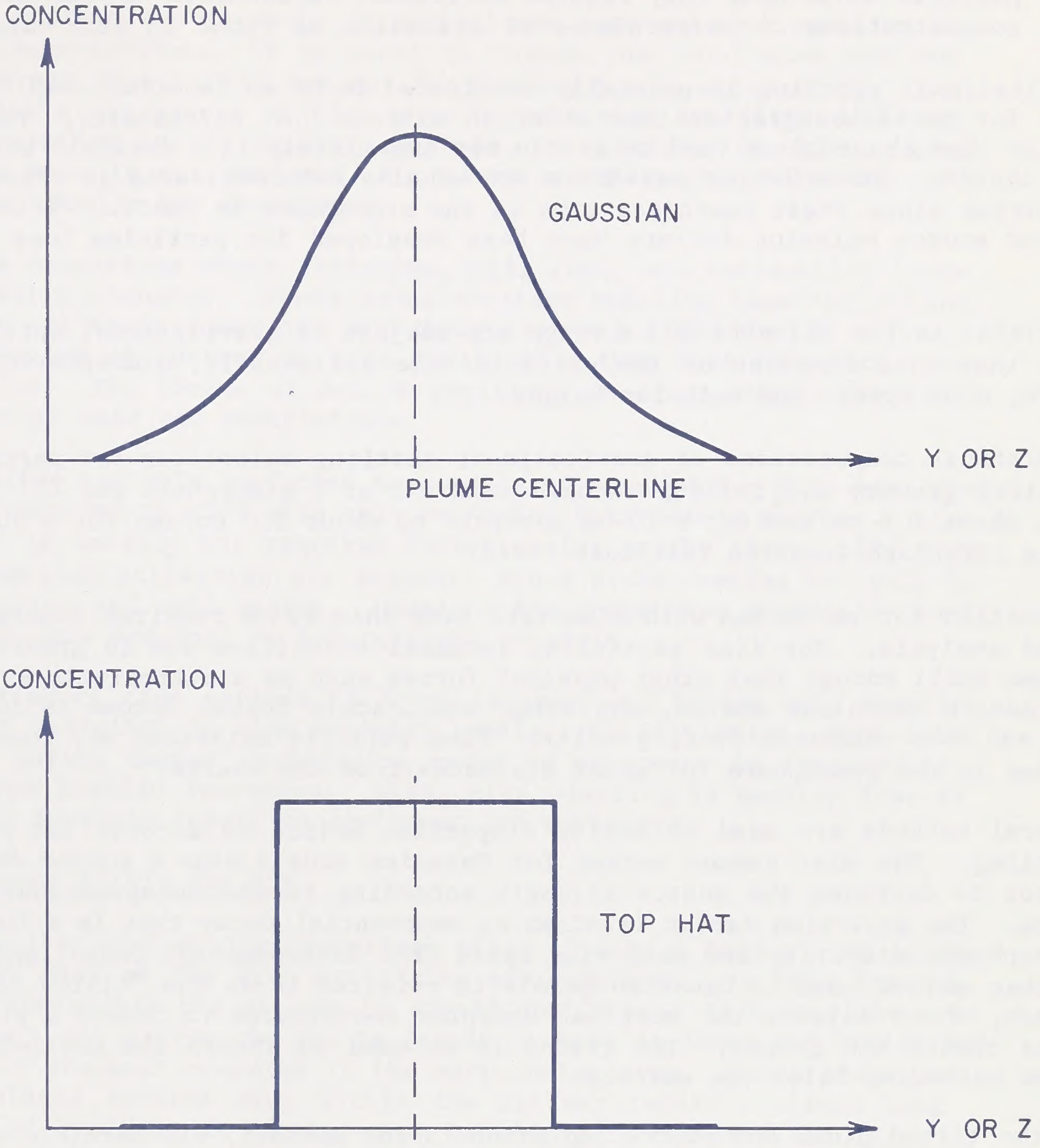
Steady-State Meteorology and Emissions

The real atmosphere is in a constant state of fluctuation over a range of length and time scales. Modeling methodologies, however, always require some level of simplification of meteorological conditions which usually takes the form of assuming those conditions (wind velocity, atmospheric stability, etc.) remain in a steady state over some period of time. A meteorological condition does not vary with time, such as a wind field, is referred to as stationary.

Likewise, pollutant emissions from an operating coal mine fluctuate over any period of time due to the mix of mining activities that result in pollutant emissions. Modeling of these emissions requires that they be averaged over the period of interest, invoking the assumption that emissions are in a steady state for some time period.

Mining emissions vary over several time scales. Emissions from individual sources fluctuate over periods of only a few minutes, depending on the specific activity level. Emissions from the mine as a whole usually fluctuate over daily, seasonal, or yearly time periods. A key modeling requirement is that emission fluctuations are reduced to a steady state for the same time period for which concentration calculations are made.

Additionally, fluctuations in mine emissions are important in determining worst-case air quality impacts for short time scales (generally 1-hour, 3-hour, 8-hour, or 24-hour periods). In a worst-case analysis with constant-level mine emissions, the only considerations are meteorological. The worst case is defined by wind and atmospheric stability. However, when the emission rate fluctuates over the time period, worst-case analysis must consider a match of both worst-case meteorological conditions and highest emission rates. In many analyses of this type a determination must be made of the probability of the simultaneous occurrence of both worst-case meteorological conditions and highest emission rates.



GAUSSIAN AND TOP HAT DISTRIBUTIONS FOR INSTANTANEOUS PLUME CROSS SECTIONS

FIGURE 10

Particle Settling

Most air quality dispersion models (including Gaussian models) are not specifically designed to model concentrations of particulates that are subject to gravitational settling. Although these models apply well to gaseous pollutants and fine particle emissions, they require additional refinements to accurately predict concentrations of particulates of all sizes as found in mine emissions.

Gravitational settling is generally considered to be an important depletion method for particles greater than about 10 microns (μm) in diameter. Particles larger than about 30 μm tend to settle out immediately in a dustfall surrounding the source. These larger particles are usually not considered in emission inventories since their residence time in the atmosphere is short. Virtually all mining source emission factors have been developed for particles less than 30μm.

Particles in the 10 μm to 30 μm range are subject to gravitational settling at a rate that is a function of the particle size and density, atmospheric turbulence, wind speed, and emission height.

Theoretical computations of gravitational settling velocities for particles of specific gravity 2.0, falling through calm air at 1 atmosphere and 25° C, range from about 0.6 cm/sec for a 10-μm particle to about 5.0 cm/sec for a 30 μm particle (Stanford Research Institute 1961).

Deposition for particles with diameters less than 10 μm requires a more complicated analysis. For fine particles, terminal velocities due to gravity alone become small enough that other physical forces such as electrostatic attraction, microscale turbulent eddies, and other small-scale forces become as important as, and even dominant over, gravity. Fine particle emissions may remain suspended in the atmosphere for great distances from the source.

Several methods are used to modify dispersion models to account for particle settling. The most common method for Gaussian models uses a source depletion factor to decrease the source strength according to the receptor-source distance. The depletion factor is often an exponential decay that is a function of atmospheric stability and mean wind speed (TRC Environmental Consultants 1981). Another method used in Gaussian models is referred to as the "tilted plume" approach, which adjusts the vertical receptor coordinates to create a plume that tilts toward the ground. The ground is assumed to absorb the portion of the plume extending below the surface.

In the tilted plume and source depletion factor methods, all particle sizes are considered as a whole. Differences in fallout rates due to particle size cannot be included; thus, these methods only coarsely approximate actual particle fallout.

More sophisticated grid models allow time-stepped chemistry algorithms that can include deposition as a depletion method. These models more realistically simulate actual particulate fallout since particle size distribution can be simulated.

Mine Operations and Emission Assumptions

When emissions from an operating mine are modeled, several assumptions and simplifications are made for many of the mine operations in order to use standard EPA models.

Most coal mines operate continuously throughout the year and when modeling for annual-average concentrations, it is usual to assume that most mine sources operate 365 days per year. This may not be precisely true since every mine operation includes a percentage of time when certain mine activities will not maintain full operation due to weather, mishaps, or scheduled downtime. However, unless the mine is not designed to operate continuously, this loss of operating time is usually not considered.

Mines are moving operations where stripping, pit, road, and reclamation locations are constantly changing. Since annual-average modeling requires defined source locations and these locations may change several times during a year, some average position of sources must be established that best represents the year to be modeled. The choice of source positions is often subjective but based on mine design maps and descriptions.

Some mine activities are only performed seasonally or as needed. Mine haul road watering is not required on days with rain or during subfreezing weather. Also, road maintenance is usually not required during winter months (except for snow removal). Reclamation activities are seasonal since grass seeding can only be done in early spring and fall months. Modeling for these mine activities must take into account this seasonal or intermittent schedule.

Modeling of very short time periods (8 hours or less) can become very complicated due to the variation in mine activity levels. In particular, work shift changes cause a marked change in emission rates as equipment is temporarily idled and employee traffic increases. Also, mine blasting is usually done at the shift changes to avoid injury to equipment and employees.

Particle Containment Within the Pit

Open-pit and dragline coal mining operations often involve a deep pit or longitudinal cut where many of the mine activities are confined. In this type of mining the air flow within the pit may be significantly less than over the surrounding surfaces. Air within the pit is likely to move at lower velocities and at times be quite stagnant compared to the surrounding area. Under these conditions, particulates emitted deep within the pit may remain confined long enough for much of the dust to settle out. Depending on the size and depth of the pit, the particle size distribution of the source, and the specific meteorological conditions, the effects of pit retention may be significant.

Concern over the significance of pit retention in relation to modeling has developed only recently, but one study has been made which quantifies pit retention at two operating coal mines (TRC Environmental Consultants 1981). In this study emission rates were calculated for each source within the mine pit and added. As a check of the sum of the mine emissions, a whole-mine emission rate was developed based on hi-vol measurements from the pit periphery. The hi-vol concentrations were used in combination with a Gaussian dispersion model and standard particle deposition methods to compute the whole-mine emission rate.

At both mines in the study, the whole-mine emission rate was about one-third that of the added emission rates. This led to the conclusion that the difference between the two emission rates indicated the amount of particulate emissions retained in the pit.

More research into this question is needed, but the preliminary results show that pit retention is an important depletion mechanism not currently considered in modeling mine air quality impacts. Although the calculations supporting this conclusion have only recently been made, depletion by pit retention has been plainly evident to mining industry personnel for some time.

In summary, a simplistic analysis performed economically using conservative modeling assumptions is sometimes adequate to comply with applicable air quality standards. Models with exotic capabilities are available to more accurately consider the specific characteristics of the site and mining operation. These more sophisticated models involve a substantially more expensive analysis effort and are limited by the accuracy and representativeness of the meteorological and emissions data used. In fact, the monitoring and modeling analyses must be considered integral parts of the impact analysis.

Technical complexity of air quality modeling requires personnel experienced in computer programming and air quality analysis, as well as correlation with permitting agency personnel. Because of the wide range of options available and the large consequences involved, conference with the permitting agency is a necessity.

Baseline Data

Regulatory Requirements

Baseline meteorological air quality data applicable to the project area are required in all air quality permit applications. These baseline data are used to define existing conditions so that the incremental impacts resulting from the project may be accurately related to existing conditions. If terrain and proximity of data taken for other projects allow adjacent data to be realistically extrapolated onto the project site, monitoring may not be required by the responsible agency.

Regardless of whether existing data from adjacent projects are used or a new monitoring program is undertaken, the baseline data collection program should satisfy four objectives:

1. Define existing levels of ambient concentration for the pollutants regulated under the Clean Air Act so that when projected increases calculated by the air quality modeling are added to this baseline, a correct assessment may be made as to whether the project design as proposed will meet the applicable ambient air quality standards. Because

particulates are the predominate surface mine emissions, on-site air quality monitoring generally consists only of particulate sampling. Baseline levels of other required pollutants are generally inferred from existing regional sampling program data available to the staff preparing the permit application.

2. Provide a site-specific meteorological data base adequate to supply the input data for air quality modeling which may be undertaken. The modeling strategy will determine some of the parameters measured and the data processing which is undertaken. Commonly, wind speed and direction, temperature, precipitation, and some parameter by which atmospheric stability may be inferred are minimum requirements for the meteorological monitoring program.

3. Provide data on design constraints which may be applicable to the site, which include data by which the watering frequency for haul roads, the wind erosion potential, and control strategy for exposed areas and storage piles may be planned. It may also include data on wind and snow loading, site hydrology, frost depths, and other facilities design parameters.

4. Be structured so that the "before-and-after" effects of the emission control plan presented in the permit application may be quantified. Air quality agencies commonly require that poststartup monitoring be conducted for at least the first year to demonstrate the effectiveness of controls.

The cost effectiveness of data collection programs will be significantly enhanced if consistent coordination with the permit approving authority is maintained throughout the data collection activities. Before initiating any data collecting programs, the agency should be given the opportunity to approve the siting, instrumentation, and data reduction plans, the plans for data utilization in the modeling, and the use of off-site data in the planned analysis. Generally these plans are submitted in a monitoring plan document which is approved by the agency prior to instrument installation. Where the use of adjacent, nonproject data is proposed in lieu of undertaking a new measurement program on-site, the agency can facilitate the delivery of the data from their files.

Each agency has its established standards and guidelines on the design, operational conduct, data reduction and quality assurance standards, and data reporting criteria as applied to specific projects (for example, Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA November 1980b). The baseline data collection program must conform to these established standards.

Model Limitations

Meteorological and air quality monitoring programs are expensive and thus are scoped to provide only the data necessary to obtain the permit to construct. An experienced air quality consultant familiar with the topography, proposed project design, and the capabilities of available air quality models can infer the data necessary to effectively augment the impact analysis. The increased data requirements of more sophisticated models are usually only justified if site characteristics such as proximity to other large emission sources or to sensitive geographic areas are applicable. Little benefit is gained by collecting monitoring data beyond the requirements of an adequate modeling analysis. On the other hand, a computer analysis will only be as accurate as the data provided it. Air quality assessment models have several recognized weaknesses which are often alleviated by obtaining additional data during the baseline measurements program. These include the model's capacity to simulate winds at the project site, especially in rough terrain; to accurately simulate the effects of atmospheric turbulence as a function of the local atmospheric thermal structure under varying weather conditions; and the effects of particle deposition. In some cases, these deficiencies are best addressed by field studies funded by a consortium of concerned mining companies and restricted in scope to specific aspects of the permitting process. Data collected in long-term monitoring programs at individual mines often provide the basis for properly extrapolating the short-term field study results to operational applications.

Relationship of Baseline Data to Calculated Concentrations

Incorrectly collected or applied baseline data can significantly affect the projected air quality impacts from the facility and thereby the ease of obtaining necessary construction permits or perhaps even the viability of the entire project. However, correctly sited and analyzed on-site data may provide the detail necessary to obtain approval to proceed with projects in areas where, based on general observations, such development would not be approved.

Off-site meteorological data extrapolated onto the project site brings with it the inference that subtle characteristics of the windfield and stability at the site are identical to the conditions at the off-site monitoring location. Extrapolated air quality data may be similarly affected. Considerable variability in meteorological conditions can exist even for nearby locations, particularly in areas of mountainous terrain (see the following section).

Normalized Air Quality Impacts

As discussed in the normalized emission rate development section, normalized mine emission rates refer to the quantity of pollutants emitted from a mine per million tons of coal. The same concept can be applied to calculate normalized air quality impacts. With these calculations, approximate mine air quality impacts may be obtained merely by knowing the mine's coal production rate.

Applicability of Normalized Impact Calculations

Although normalized impacts may be very useful, it is quite difficult to produce calculated concentrations that are applicable to any given mine. Every mine has an individual source layout that depends on the geology of the coal seam, the type of mining operation, the types of equipment used and the local transportation network. In addition, meteorological and topographical conditions range widely from mine to mine.

An important consideration in air quality modeling is the speed and direction of the prevailing winds and the average atmospheric stability. These parameters can vary, even for mines located close together. Figure 11 demonstrates the wide variability in wind direction and speed, even though sites are close together. For each wind direction and wind speed category, the windroses shown in the figure indicate the percentage of time during a year that the wind blew from that direction and with that speed. The towns of Arco and Howe, Idaho, are less than 18 miles apart, yet the prevailing winds at these two sites are completely different. (Wind at Arco prevails from the southwest, but from the northwest at Howe.)

Since model concentration calculations are highly dependent on meteorological data for the site, impacts from an identical mine at the two sites in Figure 11 would be entirely different.

Because of the problems described above, no attempt will be made in this document to develop values for normalized air quality impacts applicable to all coal mines. However, for clarity and completeness on this subject, an example of normalized impacts from one proposed coal mine is presented below. In no way can this example be applied to any other coal mine without understanding the great variability in the results due to mine source layout, meteorology, and topography.

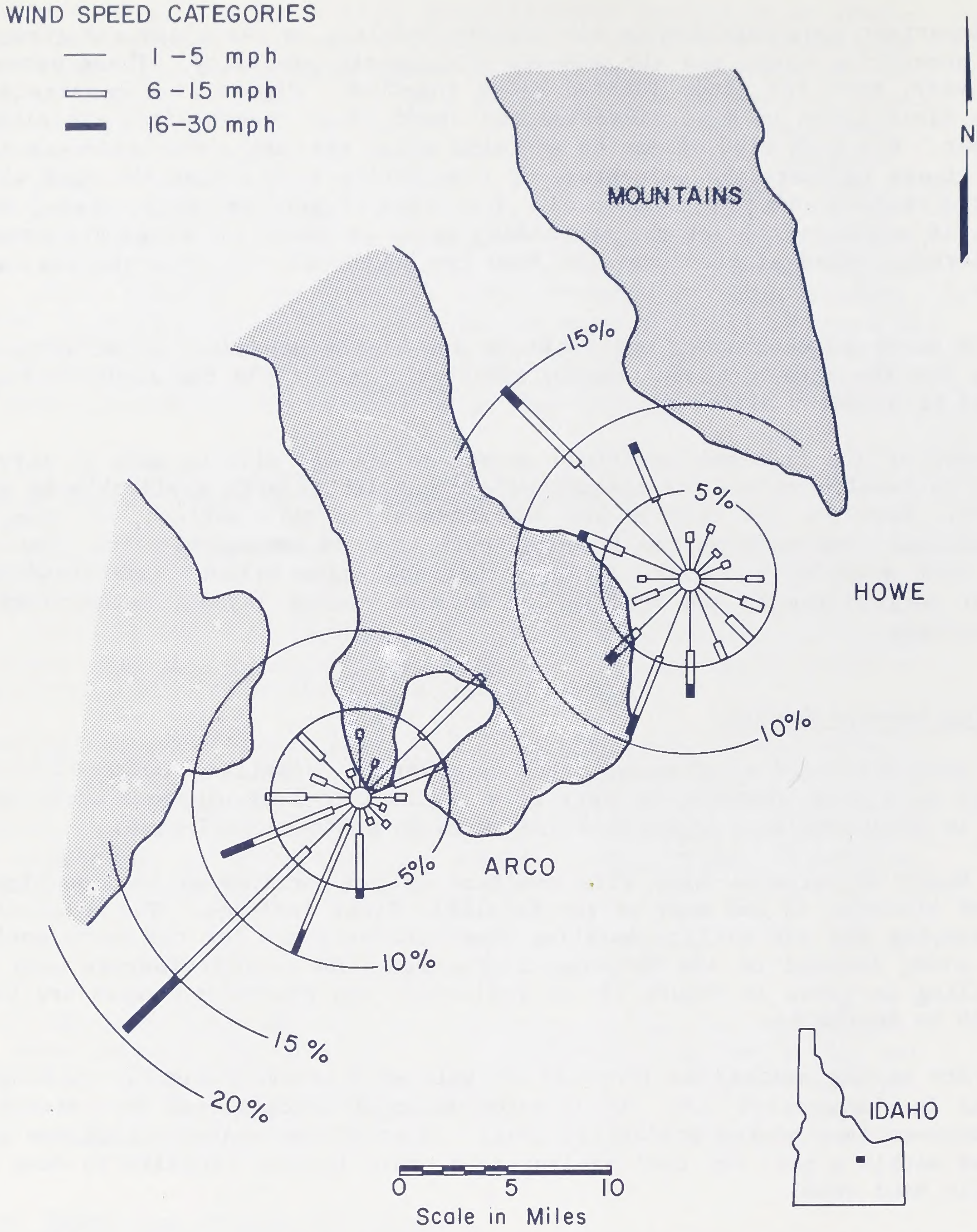
Mining Impacts Example

The coal mine used as an example for calculating normalized air quality impacts is a mine proposed as part of a regional coal development study made by BLM in 1980; the site is North Kaiparowits in south-central Utah.

The North Kaiparowits mine site consists of two portions of land on high forested plateaus to the west of the Escalante River drainage. The meteorological monitoring and air quality modeling presented here are for the south portion of the site, located on the Kaiparowits plateau. The annual windrose used in the modeling is given in Figure 12; as indicated, the prevailing winds are from the south to southwest.

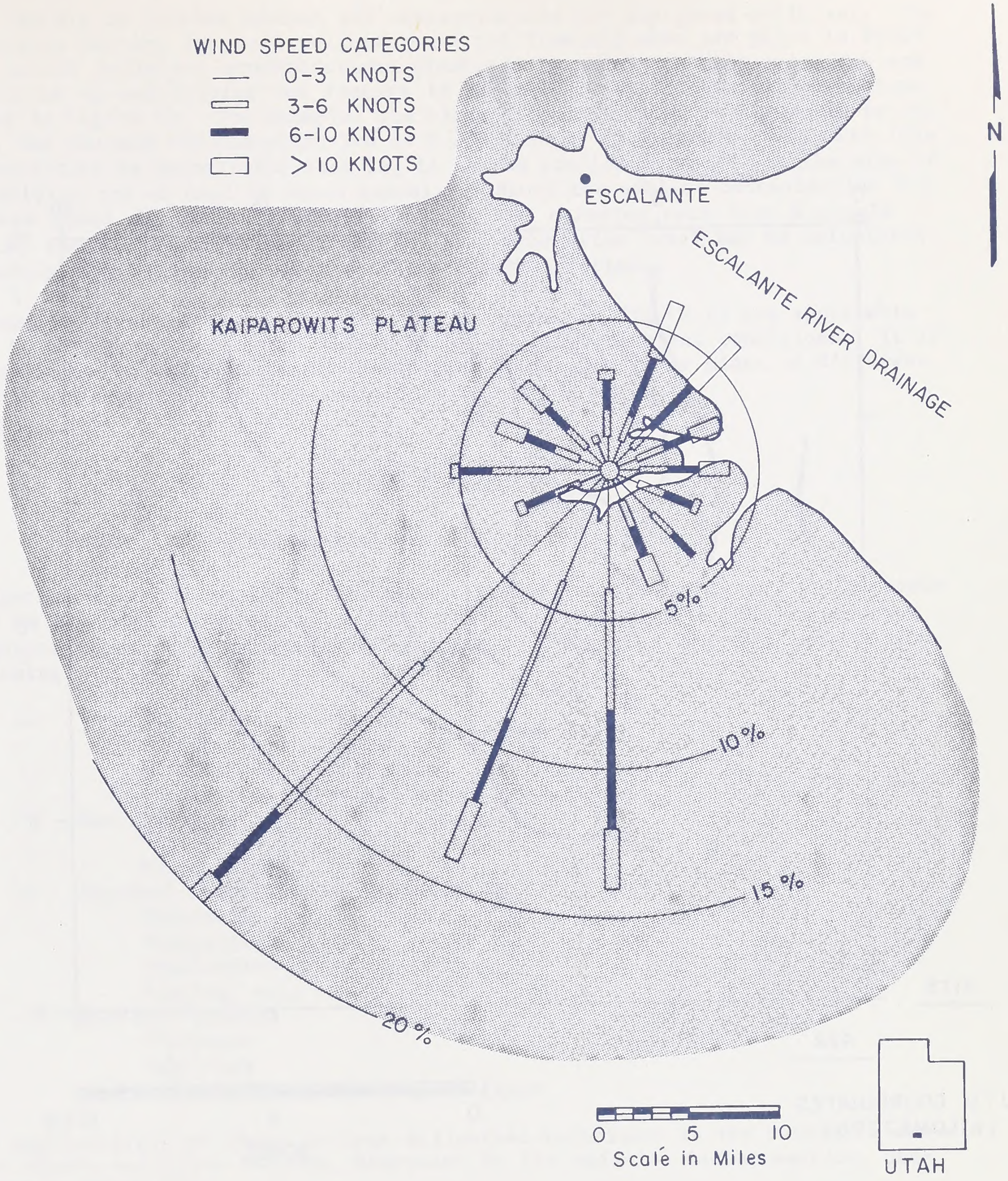
Surface mining activities proposed at this mine are very similar to other coal mines in the Western U.S. It is proposed as a truck/shovel type mine with a 2-mmtpy-surface mining production level. Most of the mining activities are confined within a pit, but coal hauling to a train loading facility is done along a 2-mile haul road.

Air quality modeling of the emissions from this mine was done using Environmental Research and Technology's ERTAQ model, a proprietory air quality model similar to EPA's Climatological Dispersion Model (CDM). The result of the normalized modeling is a contour map of concentrations for the mine area, presented as Figure 13. The contour lines on this map do not represent any specific pollutant or any specific concentration but must be used in combination with conver-



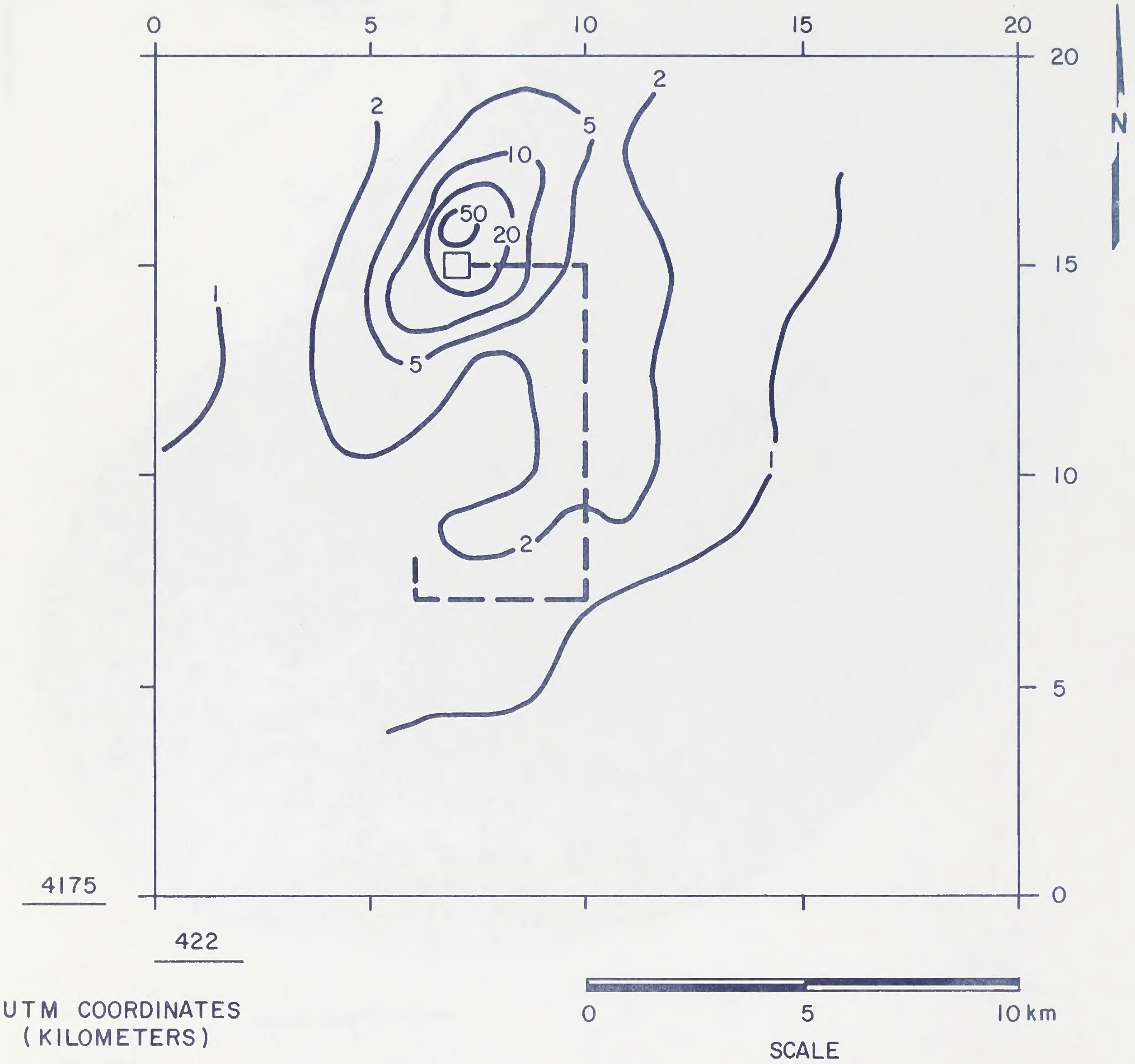
WINDROSE COMPARISON FOR NEARBY SITES
(Yanskey, et al, 1966)

FIGURE 11



WINDROSE FOR THE NORTH KAIPAROWITS MINE SITE

FIGURE 12



NORMALIZED IMPACTS FOR THE NORTH KAIPAROWITS COAL MINE (Redrafted from ERT, 1980)

FIGURE 13

sion factors to produce ambient air concentrations for any given pollutant. The conversion factors for each pollutant emitted from the mine are given in Table 10. Actual pollutant concentrations predicted by model for mine emissions are calculated by multiplying the factors in Table 10 by the concentration contour values in Figure 13. For example, the highest contour value in Figure 13 is 50; thus, the maximum TSP concentration is 0.278 x 50 or 13.9 $\mu g/m^3$. Note that this concentration is normalized; that is, it is the predicted impact for the mine if one million ton of coal is mined annually. Since the ambient concentration for a given point is directly proportional to the emission rate from a single source, the air quality impact for any coal production level may be calculated by multiplying by the appropriate coal production factor.

It must be stressed again that the impacts given in Figure 13 are applicable only to that particular mine configuration and meteorological conditions. It is not possible to extrapolate these modeling results to other mines in different terrain and under different meteorological conditions.

MITIGATION MEASURES

Mitigation Alternatives And Effectiveness

Mitigation measures consist of those operational practices or physical equipment used in the mining operation to limit the amount of fugitive dust or gaseous emissions which would otherwise be produced. Mitigation measures include the following:

-- "Best Management Practices"
    *Limited equipment access
    *Restricted vehicle speed
    *restricted material drop height, etc.
-- Dust suppression
    *Water
    *Chemical/oil
-- Physical stabilization or isolation
    *Barriers
    *Compaction
    *Enclosures
    *Paving, etc.
-- Particle removal
    *Baghouse
    *Cyclones
    *Screening and handling of fines

The applicability of these various mitigation techniques to the potential surface mining emissions factors, discussed in the emission factor section, presented in Table 11.

Gaseous emissions from fuel evaporation, engine exhaust, and blasting are a small portion of the total emissions at any mine. Emission mitigation for these activities is usually confined to the best management practices of controlling

TABLE 10. NORMALIZED CONVERSION FACTORS FOR NORTH KAIPAROWITS MINE IMPACTS*

Pollutant	Factor
TSP	0.278
RSP	0.101
HC	0.00298
NO_x	0.013
SO_x	0.00182
CO	0.0139
Pb	0

* Use these conversion factors in combination with Figure 13 to produce normalized pollutant concentrations for an annual average. (Based on mining 1 mty of coal.)

TABLE 11. MITIGATION TECHNIQUES AS THEY APPLY TO SURFACE MINING EMISSION SOURCES

Emissions Source	Best Management Practice	Wet Suppression	Chemical/Oil Stabilization	Physical Stabilization	Particle Removal Devices
1. Material Removal					
a. Topsoil removal	Minimize stripped areas	Pre-water disturbed areas	N/A	N/A	N/A
	Restrict travel to designated haul paths				
	Speed control				
	Minimize distance traveled				
	No open burning				
b. Overburden removal	Minimize fall distance	N/A	N/A	N/A	N/A
	Dump in pit area				
c. Coal removal	Minimize fall distance	N/A	N/A	N/A	N/A
	Dump in pit area				
2. Drilling					
a. Overburden	Optimum blasting plan design	Water injection system	N/A	N/A	Hooded dust collection system
b. Coal	Optimum blasting plan design	Water injection system	N/A	N/A	Hooded dust collection system

TABLE 11. (Continued)

Emissions Source	Best Management Practice	Wet Suppression	Chemical/Oil Stabilization	Physical Stabilization	Particle Removal Devices
3. Blasting					
a. Overburden	Minimize area to be blasted Avoid overshooting (optimum powder factor)	Water bladders	N/A	Blast retarding barriers	N/A
b. Coal	Minimize area to be blasted Avoid overshooting (optimum powder factor)	Water bladders	N/A	Blast retarding barriers	N/A
4. Stockpile Material Handling (loadin and loadout)					
a. Topsoil	Unload on downwind side, using pile as windbreak Minimize fall distance (bottom dump or scraper placement)	Watertruck following dump	N/A	Compaction during dump	N/A
b. Overburden	Minimize fall distance	N/A	N/A	N/A	N/A

TABLE 11. (Continued)

Emissions Source	Best Management Practice	Wet Suppression	Chemical/Oil Stabilization	Physical Stabilization	Particle Removal Devices
c. Coal	Stacker reclaimer system				Negative pressure system at truck unloading (baghouse)
	Minimize fall distance				
	Unload on downwind side using pile as windbreak	Water spray at truck unloading, pile loadin, loadout	Chemical stabilization of inactive storage piles at loadin	Enclosed truck unloading	Separate storage of finely divided material
	Unloading sock to restrict wind on fall stream				Negative pressure telescoping drop tube
5. Crushing Loadin	Minimize fall distance	Water spray at loadin	N/A	Enclosed truck or conveyor dump	Negative pressure system serving loadin (baghouse)
6. Crushing and Screening	N/A	Water spray at exhaust	N/A	Enclosed crushing/ screening facility	Negative pressure system for entire crushing/screening facility
					Screening and removal of fines at each crushing stage

TABLE 11. (Continued)

Emissions Source	Best Management Practice	Wet Suppression	Chemical/Oil Stabilization	Physical Stabilization	Particle Removal Devices
7. Conveyors and Transfer Points	Belt reversal (dirty side up) on return trip	Water spray at transfer point	Surfactant or oil spray at transfer points	Coverage of loaded belt, with side panel (partial enclosure); dribble pans at crossings	Negative pressure systems at transfer points (baghouse)
	Wetting of entire product prior to placement on conveyor system			Total (gallery) enclosure of conveyor system	
8. Wind Erosion					
a. Stockpiles	Wind screens	Watering storage pile	Chemical stabilization of storage piles	Enclosed or covered storage	N/A
	Revegetate rapidly				
b. Exposed areas	Wind breaks	Watering (construction) areas	Chemical stabilization (crusting agents) on on exposed areas	Paving	N/A
	Minimize stripped areas				
	Forrow areas				
	Revegetate rapidly				

TABLE 11. (Continued)

Emissions Source	Best Management Practice	Wet Suppression	Chemical/Oil Stabilization	Physical Stabilization	Particle Removal Devices
9. Haul Roads	Minimize distance traveled Maintain road surface and remove loose debris Restrict travel to maintained roads Speed control	Watering haul	Chemical stabilization	Paving	N/A
10. Access Roads a. Employee Traffic	Use of buses for employee traffic Regarding sanding paved roads for snow and ice control Replace sand with salt or sand/salt mixture Plow streets instead of sanding	Watering	Chemical (oiling) stabilization	Paving Curbing	N/A

TABLE 11. (Continued)

Emissions Source	Best Management Practice	Wet Suppression	Chemical/Oil Stabilization	Physical Stabilization	Particle Removal Devices
10. Access Roads (Cont'd)					
a. Employee Traffic	Clear sanding material as soon as possible after each storm Restrict sand application to intersections, hills, and curves Wash and size sand				
b. Other	N/A	Watering	Chemical stabilization	Paving	Street cleaning
11. Road Maintenance	Regarding sanding paved roads for snow and ice control Replace sand with salt or sand/salt mixture Plow streets instead of sanding Clear sanding material as soon as possible after each storm	Watering	Chemical (oiling) stabilization	Paving Curbing	Street cleaning

TABLE 11. (Continued)

Emissions Source	Best Management Practice	Wet Suppression	Chemical/Oil Stabilization	Physical Stabilization	Particle Removal Devices
11. Road Maintenance (Cont'd)	Restrict sand application to intersections, hills, and curves				
	Wash and size sand				
12. Railcar Loadout	Minimize drop height	Watering	Surfactant or oil spray at loadout	Enclosure	Negative pressure telescoping drop tube
	Sock to restrict wind on coal stream				Negative pressure serving entire loadout facility
13. Railcar Blowoff	N/A	Wetting surface	Chemical binders	Covered rail cars	N/A
14. Material Truck Dumping	Use of bottom dump in lieu of end dump trucks where feasible	Water spray system	Chemical wetting agent	Enclosure	Negative pressure system at hopper
	Unload on downwind side of pile, using pile as windbreak				

TABLE 11. (Continued)

Emissions Source	Best Management Practice	Wet Suppression	Chemical/Oil Stabilization	Physical Stabilization	Particle Removal Devices
15. Equipment Exhaust					
a. TSP	Regular service to optimize power and extend engine life	Exhaust spray for spark suppression	N/A	N/A	N/A
b. SO_x	Use of low sulfur fuels	N/A	N/A	N/A	N/A
c. NO_x	Avoid use of catalytic converters	N/A	N/A	N/A	N/A
	Regular service to optimize power and extend engine life				
d. VOC	Regular service to optimize power and extend engine life	N/A	N/A	N/A	N/A

fuel spills, maintaining engines for optimum performance, and using an optimum powder factor in blasting operations.

In preparating an air quality impact analysis during the permitting activities for a mine, projected dust concentrations in the ambient atmosphere (outside air to which people have access) are calculated based on emission levels for each source taking into account the effect of any applicable emission controls. These controls are specified in the project design. Because the impact calculations for permits are based on projected emissions after applying controls, the effectiveness ascribed to the selected control strategy is as important an influence on the projected impacts as is the emission factor itself.

Selecting a Mitigation Strategy

Not all of the mitigation techniques for a given source outlined in Table 11 are equally effective. Therefore, an evaluation of the effectiveness of each technique is important in selecting the appropriate mitigation strategy. Table 12-A through 12-E presents the effectiveness ascribed to the various control options specified in Table 11 -- best management practices, chemical/oil stabilization, particle removal devices, physical stabilization, and wet suppression -- in reducing source emissions.

In many cases the viability of an available control technique depends heavily on design characteristics which may be unique to each project. For instance, paving a section of haul road may be feasible for a short road section used for a long period of time but may be uneconomical for a lengthy temporary haul route. Chemical stabilization of a storage pile to prevent wind erosion may be desirable for a small, permanent storage pile. However, such stabilization would be inappropriate for large "live storage" piles which are frequently disturbed.

The choice of an appropriate control strategy to mitigate air quality emissions must consider not only the effectiveness available in specific controls and their congruity with the overall facilities design, but also must consider overall cost effectiveness, energy efficiency, and their potential for undesirable environmental impacts. Such an analysis is conducted separately by both the applicant (in the facilities design and permit application preparation activities) and by the permitting authority (in the permit approval process).

The cost effectiveness of alternative emission controls is closely related to specific characteristics of each individual mine and is difficult to quantify in a general sense. Even normalized cost comparisons, such as dollars per ton of emission controlled, are difficult to formulate unless an emission factor (of which there may be several available for each source) is specified. Cost differences between various controls alternatives are addressed as they apply to each of the sources in the section on optimizing control measures.

Individual permitting agencies have differing opinions of what appropriate and cost-effective controls may be, based on local environmental and economic conditions which change with time. They vary with topography and local meteorology and by political subdivision. A dialogue between the project sponsor and the

TABLE 12-A. BEST MANAGEMENT PRACTICES

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining	Blasting	Minimize area to be blasted	-		Control effectiveness function of area
		Avoid overshooting			
	Coal and waste handling	Minimize fall distance	-		
	Truck unloading (at an open pile)	Unload on downwind side using pile as a windbreak	-		
	Storage pile loadout	Stacker/reclaimer	25-50%	b	
	Storage pile wind erosion	Wind screens	-		Very poor control efficiency (Carpenter and Weant 1978)
	Wind erosion	Wind breaks	50%	c	
		Minimize stripped areas	-		
		Furrow areas	-		
		Revegetate rapidly	75%	c	Within 1 growing season

TABLE 12-A. (Continued)

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining (Cont'd)	Haul roads	Minimize distance traveled	-		
		Maintain road surface to remove loose debris	-		
Haul roads		Restrict travel to maintained roads	-		
		Speed control	25% for 30 mph 65% for 20 mph 80% for 15 mph	d	Assuming uncontrolled speed is 40 mph. Dust emissions are linearly proportional to vehicle speed for speeds from 30 to 50 mph. Below 30 mph, emissions are proportional to square of vehicle speed (EPA 1975).
Coal transport	Unpaved roads	Minimize distance traveled	-		
		Maintain road surface and remove loose debris	-		
		Restrict travel to maintained roads	-		
		Speed control	(See above)		

TABLE 12-A. (Continued)

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Secondary sources	Construction	Minimize exposure of stripped areas	-		
	Unpaved roads	(See above)			
	Sanding paved roads for snow and ice control	Replace sand with salt or a sand/salt mixture	-		
		Plow streets instead of sanding	-		
		Clear sanding material as soon as possible after each storm	-		
		Restrict sand application to intersections, hills and curves	-		
		Wash and size sand			

* Dashes indicate control efficiency highly variable or not qualified.
Advance agency approval of all credits for emissions reductions is required.

[a] Reference Numbers given refer to footnotes.

[b] Cutze et al. 1977

[c] EPA 1979

[d] EPA 1975

TABLE 12-B. CHEMICAL/OIL STABILIZATION

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining	Truck unloading	Chemical wetting agent	90%	b	
	Storage pile loadin/loadout	Chemical stabilization	≦90%	b	Continuous chemical treatment of material loaded onto piles, coupled with watering or similar treatment of roadways, can reduce total particulate emissions from storage operations by up to 90% (EPA 1975). But other surveys claim that, as with watering, constant movement of material in and out of storage pile negates dust control effectiveness of chemical treatment (Carpenter and Weant 1978)
	Storage pile wind erosion	Chemical stabilization	90%	b	For active piles, actual degree of effectiveness is probably dependent on amount of disturbance and fracturing of crust formed by chemical agent (Carpenter and Weant 1978)

TABLE 12-B. (Continued)

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining	Wind erosion	Chemical stabilization	85%	c	May interfere with later revegetation
	Haul roads	Chemical stabilization	85% 65% 50% 50%	c d b e	Control efficiency of chemical dust suppressant on roadway is extremely variable depending on chemical used, method of application, dilution ratio, frequency of application, and type and amount of traffic. For heavily traveled roads, frequent retreatments are required for this method to be effective.
Coal transport	In-transit windage	Chemical binders	≦90%	f	Control effectiveness depends on length of exposure and total wind velocity coal particles are subjected to. (Control efficiency estimated by ERT from results of wind tunnel tests.) Other studies indicate that effectiveness of chemical binder to control in-transit dust losses is

TABLE 12-B. (Continued)

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
					dependent on loading profile or geometric configuration of exposed coal surface, loading method, and chemical application technique.
	Unpaved roads	Chemical stabilization	(See haul roads above)		
Secondary sources	Construction	Chemical soil stabilization			Primarily effective in controlling windblown dust from exposed areas.
	Unpaved roads	Chemical stabilization	(See haul roads above)		

[a] Reference numbers given refer to footnotes.
[b] Gutze et al. 1977
[c] EPA 1979
[d] Wyoming Department of Environmental Quality 1979
[e] EPA 1975
[f] Nimerick and Laflin 1977

TABLE 12-C. PARTICLE REMOVAL DEVICES

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining	Drilling	Hooded dust collection system	90%	b	
	Truck unloading (hopper)	Negative pressure system	85%	b,c	Large fans draw air with fine particles down into hopper preventing them from becoming airborne.
	Storage pile	Baghouse	99%	d	Fabric filtration system which removes dust particles from enclosed air before venting to atmosphere. Must be accompanied by fully enclosed structure.
Secondary sources	Paved roads	Street cleaning	-		Street cleaning has not been proved to be effective method for reducing ambient particulate concentrations; street cleaning only reduces street dust available for reentrainment and dust reentrainment is not significant source.

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[a] Reference numbers given refer to footnotes.

[b] EPA 1979

[c] Wyoming Department of Environmental Quality

[d] PedCo 1976a

TABLE 12-D. PHYSICAL STABILIZATION

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining	Windage and spillage from loaded haul trucks	Tarpaulin cover	-		Effectiveness of this method in controlling loss of material from loaded haul trucks has been rated fair (Carpenter and Weant 1978). One primary concern is that covering truck loaded during onsite hauling could cause delays during loading and unloading process.
	Truck unloading	Enclosure	70-99%	b	Control efficiency depends on type of enclosing structure (full or partial) and on any additional venting equipment. This method can be costly.
	Storage piles	Enclosed or covered storage	95-99% 99%	c d,e	These control efficiencies represent fully enclosed storage; effectiveness of partial enclosure or cover is probably less. Full enclosure may not be practical for all types of storage because of cost.

TABLE 12-D. (Continued)

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining	Storage piles	Separate storage of finely divided material	-		Control effectiveness is dependent on size of material left in open storage; but feasibility and cost effectiveness is dependent on minimizing amount of material put in enclosed storage. Screening process itself, unless carefully controlled, may contribute more to airborne particulate than is removed through separate storage of fines.
	Haul roads	Paving	85% 85-100%	b,e d	Lower control efficiency (70%) is given to chip seal surface (Wyoming DEQ 1979). Test study in Maricopa County, AZ, showed paving to be 100% effective in controlling dust on formerly unpaved road. However, cost can be substantial.
Coal	Unpaved roads	Paving	(See above)		

TABLE 12-D. (Continued)

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Secondary sources	Unpaved roads	Paving	(See above)		
	Unpaved road shoulders	Curbing	75%	f	Curbing is primarily within population centers; but since major portion of vehicle miles are travelled within towns, street improvements there will have far greater impact on regional particulate levels than would similar improvements on county roads.

[a] Reference numbers given refer to footnotes.
[b] Gutze et al. 1977
[c] EPA 1975
[d] EPA 1979
[e] Wyoming Department of Environmental Quality 1979
[f] Richard and Safriet 1977

TABLE 12-E. WET SUPPRESSION

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining	Topsoil stripping	Watering	50%	b	
	Drilling	Water injection system	90%	c	
	Shovel excavation	Watering	-		Continuous activity reduces effective control (Carpenter and Weant 1978)
	Wind and spillage from loaded haul trucks	Wetting surface	-		Temporary but may be effective for short hauls
	Truck unloading	Water spray system	50%	c,d	Only applicable if wet product can be tolerated
	Storage pile loadin/loadout	Water spray	50%	c,d,e	Continuous activity reduces effective control (Carpenter and Weant 1978)
	Storage pile maintenance	Watering	50% 40%	c f	Watering is useful mainly to reduce emissions from vehicular traffic in storage pile area. Watering of storage piles themselves typically has only very temporary effect on total emissions (EPA 1975)
	Storage pile wind erosion	Watering	50%	c,d	Temporary

TABLE 12-E. (Continued)

Source Class	Source Type	Control Method	Estimated Control Efficiency	Reference[a]	Comments
Mining	Haul roads	Watering	50%	d,e	Temporary
Coal transport	Unpaved roads	Watering	50%	d,e	Temporary
	Intransit windage	Wetting surface	-		Temporary, ineffective for long hauls (Carpenter and Weant 1978)
Secondary sources	Construction	Watering	30%		Average control efficiency with daily watering and complete coverage. Extensive wetting at construction site may reduce emissions up to 60-70%. There is negative trade-off, however, associated with watering at construction site; mud carried out into adjacent street is susceptible after drying to suspension in wake of passing vehicles.
	Unpaved roads	Watering	50%	d,e	Temporary

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[a] Reference Numbers given refer to footnotes.
[b] PedCo 1976a
[c] EPA 1979
[d] Wyoming Department of Environmental Quality 1979
[e] Gutze et al. 1977
[f] EPA 1975

permitting agency regarding controls in the facility design as well as negotiating a control strategy acceptable to both parties should be initiated early in the project design phase.

An acceptable emission control design is a fundamental requirement in producing permits. For PSD sources, each of the Mountain West States, and the Federal government require the use of Best Available Control Technology (BACT) for every emissions source of the project before a construction permit will be granted. The permitting agency determines what constitutes BACT for a given operation after taking into account projected emissions and air quality impacts, economic and energy costs, and design and operational considerations. In the permit application, the applicant justifies why the proposed mine plan and facilities design represent BACT.

Some of the available control techniques are designated as preferred BACT by the various permitting agencies. Commonly accepted BACTs for various surface mine sources are presented in Table 13.

BACT is determined on a case-by-case basis for each source and application by the permitting agency. Many of these designations of controls as BACT are, therefore, negotiable based on economic design considerations specific to each project. The typical BACT controls listed in Table 13 are stated very generally. In an actual permit application, the selected controls must be presented in a form in which they can be included in the issued permit as quantifiable, enforceable permit conditions.

Operational Constraints

The degree of constraint which air quality emission controls pose to a mining operation's design criteria, operational effectiveness, or profitability is ultimately related to the quality of the mine design. Failure to properly account for industrial hygiene practices and environmental permitting requirements in the site selection, proposed mining method, and plant design commonly results in the need for expensive "fix-ups" to the plant facilities design and perhaps the mine plan itself during the permitting process. If an inadequate design is formally submitted with the application, the result is often a frustrating set of delays and expenses as the agency requirements are merged with a pre-existing plan. The effort spent in redesigning the mine or facilities may represent a significant engineering and financial investment.

The viability of any proposed design and associated control alternative is determined by its cost effectiveness, operational feasibility, and risk and safety considerations. Cost will eventually be the overriding consideration. Because project characteristics vary so widely, a generic constraint analysis usable for a wide range of differing projects is not feasible. Nevertheless, the following operational considerations are commonly encountered in selecting preferred emission controls and in evaluating alternative designs:

-- Geographical plant layout relative to the mine so haul roads lengths and areas exposed to wind erosion are minimized (often determined by the mine plan).

TABLE 13. TYPICAL BACT CONTROLS FOR A SURFACE MINING OPERATION

Source	BACT Control
1. Material removal	
a. Topsoil	Controls usually not practiced or required due to relative moistness of the soil. Use of water on defined haul paths.
b. Overburden	Controls usually not required.
c. Coal	Controls usually not required.
2. Drilling	
a. Overburden	Use of bag type collector on air drill or water injected or chemical suppressants.
b. Coal	
3. Blasting	
a. Overburden	Minimize area to be blasted and prevent overshooting.
b. Coal	
4. Stockpile material handling (loadin/loadout)	
a. Topsoil	Minimize fall distance of material (dragline, truck shovel, front-end loader). Use of bottom dump trucks.
b. Overburden	
c. Coal	Baghouse on silo, retractable chute on loadout, minimize number of openings.
5. Crusher loadin	Partial enclosure negative pressure at dump point.
6. Crushing and screening	Baghouse or equivalent.
7. Conveying and transfer points	Fully covered conveyors; transfer points enclosed and vent to baghouse or equivalent.
8. Wind erosion	
a. Stockpiles	Topsoil and overburden: Rapid revegetation, mulch, chemical stabilization, or wind breaks. Coal: Enclosed storage.
b. Exposed areas	Minimize spoil pile area and disturbed area; restrict off road use, chemical dust suppressant or mulch, rapid revegetation.

TABLE 13. (Continued)

Source	BACT Control
9. Haul roads	Speed control and chemical stabilization worked into road; restrict off-road use; minimize all haulage distances; prevent overloading of trucks; covered haul trucks if haulage is on public highway.
10. Access roads	
a. Employee traffic	Paving, speed control, restrict off-road use bus service.
b. Other	Paving, speed control restrict off-road use.
11. Road maintenance	Removal of loose debris, grading, chemical stabilization of road bed after grading.
12. Railcar loadout	Spraying of coal in cars retractable chute on loadout.
13. Railcar blowoff	Chemical binder; depends on size of shipped aggregate.
14. Material truck dumping	Negative pressure at dump point or spray system on dumped material.
15. Equipment exhaust	Controls usually not specified.

-- Taking advantage of local terrain features to limit exposed areas and mitigate wind erosion (often determined by project geology).

-- Regulatory agency liaison adequate to incorporate necessary permitting provisions during conceptual design phase. Hesitancy to select a consultant and contact applicable agencies often necessitates additional expenditures.

-- Matching investment costs of pollution control equipment to the significance of emission sources during the design phase. BACT analysis conducted early in the design phase can identify profitable trade-offs before engineering time is invested in nonviable options.

-- Adequate correlation between air quality design and water control and vegetative reclamation plans. Emissions from water control and reclamation work commonly require amendments to the air quality permit application and lead to mutual delays without correlation.

-- Balancing paving or road stabilization costs against costs of an exclusive bus fleet to mitigate access road impacts (often determined by project size and centralization of labor force relative to site access routes).

-- Use of scrapers versus blasting and truck/shovel for overburden or product excavation, based on geological and equipment considerations.

-- Consideration of the amount of drilling and blasting required, choice of drill equipment, selection of explosive and detonation scheme, the aggregate size desired, material characteristics, and equipment capabilities.

-- Selection of optimally sized bottom-dump or end-dump trucks and their associated off-loading facilities (often determined by terrain, pit area available, and equipment performance).

-- Provisions for exposed surface storage of coal between the mine and plant. A wide range of options and consequences exists for load-in/load-out equipment as well as provisions for limiting emissions from wind erosion and product handling.

-- Minimization of wind erosion from open storage and exposed transportation systems. The largest client-acceptable product aggregate size is preferred.

-- In phased development projects, incorporation of a design which eliminates need for the relocation of emissions sources, if possible. Relocation often necessitates a permit amendment, including a revised modeling analysis. In phased projects, it is usually desirable to design and apply for the final operation levels on the initial application. This allows orderly facilities expansion up to the permitted capacity without costly re-permitting at each step.

- Design of conveyor systems including both belts and transfer operations to allow easy inspection and access for washdown and removal of accumulated dust. The design must accommodate both the requirements for enclosure and control of the coal dust and the requirements for cleanliness for fire prevention.

- Wet suppression of coal dust along the entire product handling route must be balanced against the tendency for spontaneous combustion of the wet product. Stacking techniques on rail and ship carriers are also a factor.

Optimization of Control Measures

Any cost-benefit analysis of alternative control measures or of alternative designs adding or deleting entire sources (and thereby their associated controls) must address the control effectiveness of individual items and their associated costs over a period of time.

When necessary, an analysis of alternative designs wherein entire sets of sources are compared with other sets in optional designs should be performed by a competent team of air quality and mining engineers.

"Benefit" as used in this discussion refers to the concept of maximum emission reduction per dollar invested in controls. This concept does not attempt to address the principle of minimum added airborne concentration per dollar invested in controls. Such an analysis would consider not only emissions (source strength), but also the accuracy of meteorological data extrapolated across terrain, the spatial relationship of sources, and also the accuracy of the computer modeling techniques themselves.

The sensitivity of predicted ambient concentrations to incremental changes in particulate controls and to changes in mine configuration has never been comprehensively analyzed (PedCo/TRC 1982). The cost-benefit comparisons presented in this section must be considered typical samples only. The cost effectiveness of any actual choices of controls will depend on details of the specific mine plan involved.

Material Removal Operations

This activity pertains to topsoil stripping and overburden and product removal using draglines, shovels, front-end loaders, and scrapers. These activities are the heart of the mining operation and commonly constitute as much as 36 percent of the mine's total particulate emissions. Controls for these sources are almost never required because the removal operation (a dust-producing activity) is not amenable to control, and its regulation would unduly restrict the mine production while returning little air quality benefit. Topsoil removal by scraper is controlled as if it were a construction source by prewatering where necessary and treating defined haul paths as haul roads or construction roads.

Drilling and Blasting

Neither the type of drilling equipment nor the type of explosive or method of blasting is regulated in air quality permitting. As a BACT condition in the permit, however, either wet suppression or a dust collector on the bit dust stream is required. As a blasting condition, "minimizing the area to be blasted" and "not overshooting" (optimization of powder factor) are usually included in the permit text; although, since these practices are not quantifiable for enforcement, implementation remains at the judgment of the mine operation.

Stockpile Operations

Where applicable, stockpile operations for topsoil and overburden are controlled using techniques similar to construction material movement and to areas exposed to wind erosion. The primary considerations are minimizing the disturbed area, stabilizing the exposed material to prevent wind erosion, and adequate treatment of the working surface of access roads to minimize wheel emissions.

Coal stockpiles for product surge capacity are a necessary component of any coal mine in order to match the quasi-continuous mine production to intermittent shipping schedules. The loading, storage wind erosion, and load-out options must be considered as a package in considering stockpile emissions control. Representative capital equipment costs and attainable emissions reductions for an 8-mmtpy operation are given in Table 14. Not considering facility construction costs, annual operating costs for the options presented are similar.

At a mine, open coal storage is most commonly acceptable for smaller operations (under 5 mmtpy) in cases where emergency surge capacity for large aggregate material (2 inches and above) is necessary between the mine and the plant. Surge capacity between the plant and the offsite transportation loadout is commonly enclosed in slot storage facilities or silos.

Crushing and Screening Operations

Full enclosure of the crushing station and ducting to negative pressure baghouse systems is a BACT requirement for all but the smallest crushing and screening operations. Air to cloth ratios of 6:1 and outlet grain loadings between 0.01 and 0.02 grains per standard cubic (foot gr/std ft^3) are common requirements.

Conveying Systems

The need to enclose conveyor systems and the degree of enclosure required depend heavily on the location and length of the belt. Generally, conveyor systems in the plant area are partially enclosed. Elevated belt sections are fully enclosed at road crossings or locations where falling material would pose a hazard. Elsewhere within the mine area the shiftable belts are usually open. Wind erosion losses from exposed belts are generally much smaller than for other sources at the mine.

TABLE 14. CAPITAL EQUIPMENT COSTS AND ATTAINABLE EMISSION REDUCTIONS FOR THREE COAL STOCKPILE OPTIONS (8-MMTY OPERATION)

Option	Typical Facility Costs (million dollars)	Typical Net Emissions (t/yr)
1. Bottom truck dump onto open storage pile, front-end loader reclaim onto load-out conveyor	$0.8	126
2. Conveyor stacker loading onto open storage pile, front-end loader reclaim onto load-out conveyor	$1.4	120
3. Conveyor stacker loading onto exposed pile, bucket wheel reclaimer onto conveyor	$4.7	6
4. Conveyor stacker loading into enclosed storage, below pile reclaiming onto conveyor	$9.2	4

Wind Erosion

Wind erosion can be a significant source of particulate matter from exposed areas of the mine which have been stripped of vegetation, but is a far less significant source when considering only exposed stockpile areas. Generally, a one-time application of a crusting agent to exposed areas is much more cost effective than repetitive water applications. Revegetation within one growing season is cost effective in those areas where revegetation is required under the terms of other mining permits. Inactive storage piles may be considered more "exposed area" and revegetated or treated with a crusting agent. Active storage areas require an approach tailored to the project characteristics. Those approaches may include enclosure, repetitive wetting, or application of crusting agents. For situations where a moist product cannot be tolerated, separate storage of fines is a viable alternative. Wind erosion mitigation options are presented in Table 12.

Haul Roads

Haul roads are often the largest source of particulates in any mining operation and a source amenable to control. Road emissions are a function of: traffic carried and total length (vehicle miles traveled), composition and traffic type (silt content, haul truck weight, speed, number of tires), and surface moisture. Haul road emissions may be effectively mitigated using controls which address various combinations of all of these factors.

Emission decreases are linearly proportional to decreases in haul road length and trips made. Larger trucks (fewer trips) are favored. The action of the wheels on the road surface and the strength of the vehicle wake are the determining factors in generating emissions for a given road surface (Shearer et al. 1981). Minimizing the number of tires and vehicle speed is also favored. The road surface may be amended to minimize the separation tendency for small particles by applying water, chemicals, or oil.

A control efficiency of 50 percent is commonly assigned to watering, at least twice a day. Spraying water on the roads has been found to reduce the emissions in proportion to the application up to a maximum of three total coverages of the road per hour when the emissions are reduced by 78 percent of their dry road value (Shearer et al. 1981).

Chemical stabilizers regularly worked into road surface with effectiveness ranging from 70 percent (oiling) to 85 percent (chemical suppressants) are commonly specified as BACT for haul roads. The costs for these controls should be compared with the cost required for watering to achieve the same level of control to determine the most appropriate procedure.

The full asphalt paving option is sometimes not viable because the transitory nature of haul roads and the large vehicle weights involved (shortened road life) seldom compensate for the increased costs. Road carpet is commonly ascribed a control efficiency of 45 percent and is a useful option in cases where operational considerations preclude working the road surface or use of water trucks. Haul road dust control strategies are compared in Table 12.

Access Roads

Full asphalt paving or equivalent stabilization is a common BACT requirement for employee access roads. The "chip and seal" requirement which commonly appears as a minimum requirement for access roads and parking areas is interpreted to mean a hard oiled surface applied over a stabilized base but without the use of a paving machine. It presupposes a hardened, stabilized base typified by the clay and scoria materials available in many coal mining regions.

On-site auxiliary roads connecting facilities at the plant and designed for service vehicles and supervisory staff are commonly graveled and treated with oil or chemicals.

Road Maintenance

No controls are usually practiced as a means to mitigate road maintenance (grader emissions), although measured emissions from this activity are larger than conveyor blowoff or storage pile load-in/load-out emissions. Agencies commonly assume that because they require chemical amendments added during the road maintenance process, the road material is moist. In an operational sense, road maintenance is a continuous activity with those roads carrying the heaviest traffic volume and weight receiving the most frequent grooming.

Railcar Loadout

Loadout of aggregate or pulverized coal onto cars of a unit train is commonly accomplished by means of an adjustable chute with telescoping lowering tube within the confines of a partial enclosure for the rail car. Wet suppression at the head pulley in the chute is sometimes required in lieu of more sophisticated controls in the enclosure.

Railcar Blowoff

Railcar blowoff is generally only a consideration in cases where pulverized coal is shipped. Applying of a crust-forming sealant to larger aggregate coal after placing in the car is not standard practice, and some mines formerly applying sealant to larger coal sizes have stopped the practice because it is ineffective in reducing particulate emissions due to cracking with the settling of the coal load.

Unstabilized pulverized coal (under 1/4-in.) has been found to continue to undergo wind erosion losses over long distances from the mine. Dust from larger aggregate coal sizes (2 in. and over) undergoes wind erosion losses within a maximum of 50 miles from the starting point. Suppliers of pulverized coal generally apply sealants, as the value of coal saved from windblown loss justifies the expense of the application.

Material Truck Dumping

Bottom-dump and end-dump trucks are used to carry and place topsoil, overburden, and coal. End-dump trucks are required when carrying large rock which would not pass through the bottom-dump discharge, and in locations (e.g., off the edge of an embankment) where placement by other means is impractical. Bottom dump trucks are generally acknowledged to have less emissions. Except at fixed truck dump locations at storage piles or plant facilities, truck dumping occurs in the open and is uncontrolled.

Equipment Exhaust

Gaseous emissions from equipment engine exhaust are not regulated in surface mine air quality permitting, although they are quantified in the impact analysis. Because changes in standard fuel/air ratios have been found to decrease gaseous emissions of one pollutant while increasing those of another, the best management practice of maintaining each engine to optimize performance and prolong engine life is generally accepted as BACT for this source. Combined surface and underground operations utilizing MSHA permissible equipment and some exhaust conditioning systems required by State mining regulations are exceptions. In these cases, spark suppression systems and catalytic converters, though required, do not result in reduced net emissions for all pollutants.

The U.S. Bureau of Mines is currently funding a comprehensive investigation of mine vehicle engine exhaust and potential mitigation strategies for surface and underground mining operations.

Blasting Emissions

Gaseous emissions from explosives detonation are not regulated in surface mine air quality permitting, although they are quantified in the impact analysis. The composition of the residual gas mixtures varies widely with various explosives and with various ratios of ammonium nitrate to fuel oil. Because the total emissions produced from this activity are relatively small, the best management practice of optimizing the production powder factor (not overshooting) is generally accepted as BACT for this source.

SUMMARY

In general, air quality analysis is a project-specific task. The effort can be facilitated through a knowledge of what and where to look for indicators of the nature of the problem and how to judge the success of the mitigation measures.

Regulatory Considerations

Federal and State regulations have been promulgated which require that particulate or gaseous emissions resulting from mining operations will not cause or contribute to violations of ambient air quality standards. Operations of proposed mines must receive a permit before mine construction and/or operation may begin. The purpose of the permit application is to present information to verify that operation of the mine will not result in violations of the established air quality standards. In addition, should emissions from stacks or vents (i.e., thermal dryers or baghouses) exceed applicable threshold values, a Prevention of Significant Deterioration (PSD) permit would be required, as mandated by the Clean Air Act. However, well-designed surface mining operations, incorporating Best Available Control Technology (BACT) to suppress pollutant emissions, should meet ambient air quality standards. Difficulties sometimes arise in cases where a proposed mine facility is sited in an area where other large sources of air pollution are already located.

Sources and Emissions

The primary pollutant emitted from a surface mining operation is particulate matter (dust), produced from movement of soil and rock and from vehicle traffic on unpaved roads. In most cases, dust produced at the mine is observed to be constrained by the pit and to settle out within a few hundred yards of the source.

Vehicle wheels, material transfer, and dumping operations are sources of airborne particulates during material removal activities (topsoil stripping, overburden removal, and coal excavation). Drilling and blasting of both coal and overburden are particulate emission sources. Placement of topsoil and overburden in stockpiles and all coal handling operations including conveying, crushing and screening and stacking and reclaiming from coal storage piles are dust sources. Wind erosion from both exposed areas or open storage piles is a particulate source. Haul roads accommodating coal and overburden trucks, employee access roads, and auxiliary roads serving the mine and plant are significant particulate sources. Particulate emissions also arise during road maintenance, truck dumping, loading of trucks and rail cars, and as blowoff and resuspended dust from moving trucks and trains.

Several gaseous substances also slightly affect the air quality at a mine site. Equipment engine exhaust accounts not only for some particulate emissions, but also for most of the gaseous emissions. These include primarily nitrogen oxides, carbon monoxide, and, in lesser amounts, hydrocarbons, lead, and sulfur oxides. Explosive detonation results in nitrogen and sulfur oxide emissions, and carbon monoxide emissions.

Analysis of lesser known pollutants such as asbestos, beryllium, mercury, and vinyl chlorides is usually unimportant because of the insignificant amounts of these materials in the coal and overburden and because combustion of these more exotic chemicals usually does not occur.

Air Quality Impacts

Emissions Factors

Emissions factors, equations used to estimate particulate emissions which would result from given mining operations and activity levels, are based on data taken during intensive field studies performed by PedCo, MRI, and others during the last 10 to 15 years. The factors are important because they form the basis for concentration estimates used to assess the air quality impacts of a given project. The summary of emissions factors presented in the emission factor section, covers a wide range of values found in the literature and identifies those emissions factors preferred by the various Federal and State permitting agencies.

As an aid to understanding the application of emissions factors, three operating mines utilizing typical surface mining methods--dragline, truck/shovel, and scraper--are compared, using the concept of normalized emission rates. Normalized emission rates are emissions expressed in tons of pollutant emitted per million tons of coal produced and are useful in comparing optional designs and mining methods. Each of the three different mining methods affects air quality differently; each has certain advantages from the standpoint of minimizing air quality impacts.

Mathematical Modeling

Regulatory agencies and industrial groups have spent a great deal of effort to develop methods to simulate actual mining impacts on air quality. The focus of these efforts has been to accurately simulate air quality impacts of dust emissions. Actual impacts depend on the size of the mine, distances between material origins and destinations, the mining methods used, and local meteorological conditions. These factors are also taken into account in the impact analysis. However, accuracy of the analysis is also directly related to the accuracy of emission factors which are used to estimate the amount of airborne dust each mining operation generates.

Once the spatial distribution and magnitude of mining dust emissions have been determined, they are input along with representative meteorological data to an atmospheric dispersion model which calculates concentrations of airborne dust. There are several models from which to choose to perform these calculations. Some have been "approved" by regulatory agencies and some offer options which are intended to make the models more accurate. The selection of a model is dependent on such factors as ultimate use of the data, local topography, available meteorological data, distribution and type of dust sources, and preferences of local regulatory agencies.

Although models are the best tool currently available for quantifying airborne pollutant concentrations and are used to site air quality monitoring instrumentation and optimize mine design as well as to assess air quality impacts, available air quality models have some significant constraints. They cannot accurately simulate a depressed source such as a mine pit. Most cannot simulate particle deposition, haul roads, and dynamic mining operations. The extrapolation of available meteorological data in rough terrain may lead to large uncertainties. Simplistic models which tend to overestimate mine impacts are the tradeoff to the use of more sophisticated models which require comprehensive and costly meteorological and emissions data.

Mitigative Measures

Regardless of what the project airborne concentrations are estimated to be, the mine plan must incorporate Best Available Control Technology as detailed in the mitigation measure section. Within the constraints imposed by the mining method and transportation mode, regulatory constraints require that the mine design represents the maximum degree of emission control obtainable, consistent with economic and energy tradeoffs. Mitigation measures are a key element because of the substantial economic and operational consequences associated with their implementation. The various agencies involved with the four states under discussion and the Federal government have established preferred control strategies and assigned effectiveness potentials, as presented in Table 12.

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BLM BLASTING IMPACTS HANDBOOK
FOR SURFACE COAL MINES

by

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INTRODUCTION

The off-site impacts of blasting in conjunction with surface coal mining have been a significant problem, especially in the East. An estimated $200 million of off-site damage was caused in the Appalachian region in 1975, and successful lawsuits, as well as out-of-court settlements, cost coal companies another several million dollars (CSPI 1977).

These impacts include:

- Flyrock through the roofs of several houses
- Flyrock damage to automobiles
- Windows shattered by airblast
- Damage to wells
- Damage to water systems
- Damage to power transmission systems
- Refusal of VA and FHA to provide loans due to probability of blasting damage

Adverse off-site impacts appear to be less common in the western States, despite the use of large quantities of explosives for blasting overburden and coal. This relative lack of reported impacts may be due to revised State and Federal regulations, relatively low population density, and relatively remote locations of most mines.

Blasting Procedures

In Western surface coal mines, specifically those in Colorado, Montana, North Dakota, and Wyoming, blasting is used to fragment the overburden and coal for removal. Although a few mines may move overburden with explosives (side casting), the usual method is to fragment material in place, then move it with a dragline or shovel.

The blasting procedure normally depends on the type of removal equipment to be used. For this purpose, mines may be classified into three basic types: dragline, truck/shovel, or scraper/shovel. Scrapers used only in unconsolidated overburden that can be ripped prior to loading. Dragline and truck/shovel use blasting to loosen consolidated overburden material before removal. Once the overburden is removed, the coal is blasted and removed by shovels or front-end loaders. Rock characteristics, seam width, and geologic structure also determine the appropriate type of explosive and blasting pattern to be used.

The DuPont (1978) and CIL (1968) handbooks are excellent references on blasting techniques.

Potential Impacts of Blasting

Most off-site impacts from blasting result from ground movement or vibration and range from barely perceptible tremors to severe structural damage and are measured by particle velocity in inches per second (ips). The airblast associated with blasting rarely causes structural damage but can be an annoyance. Airblasts in excess of 134 decibels (db) (0.1 - Hz high-pass measurement system) may cause rattling and related disturbances in 5 to 10 percent of the affected homes. Other impacts from blasting may include the contamination of water or soil, the release of gaseous by-products, and an increase in airborne particulate and flyrock.

Mitigation Measures

Carefully controlled blasting should not cause measurable damage to modern structures or wells near Westen coal mines. Off-site impacts should occur only if the blasting personnel are not following widely recognized procedures and/or nearby structures are in poor condition or have not been constructed to accepted standards.

Vibration and airblast are controlled by proper selection of the type and amount of explosive and the time delay between charges of a blast. Flyrock and dust can be minimized by properly backfilling the drill holes (called "stemming") and related techniques. Contamination of water and soil can be prevented by good housekeeping and procedural techniques.

One impact of blasting cannot be prevented: the release of gaseous by-products. Explosives accomplish their work by the rapid expansion of hot gases resulting from the almost instantaneous chemical reduction. Without the gases, there would be no explosion. However, these gases disperse rapidly under surface mining conditions and seldom cause any off-site impacts.

EXPLOSIVES

Explosive Reactions

There are two types of explosive reactions: deflagration (slow reaction rate) and detonation (rapid reaction rate). The first is present, initially, in all explosive reactions. The second will develop only when conditions are suitable. To better understand these reactions, it is necessary to consider the mechanisms of both initiation and propagation.

Initiation of a reaction is a thermal phenomenon, beginning at minute explosion centers known as "hot spots." These spots form through the application of external energy (heat, pressure, or a combination of both) supplied by an initiating device such as a blasting cap. The hot spots develop in at least one of three ways:

* Adiabatic (without gain or loss of heat) compression of tiny gas bubbles trapped within the explosive mixture.

- Frictional heating caused by sliding along solid ingredient surfaces.
- Viscous heating as explosive material is force-flowed during initiation.

In some instances, a combination of the above may occur; however, the first two methods are most common. The hot spots are usually quite small (10^{-3} to 10^{-6} cm in diameter) but still large compared with moleclar dimensions. When the hot spots do not form during initiation, no explosion will occur and the explosive material will be considered to be "dead pressed." To prevent this, artificial voids are normally built into the high-density/velocity, high-energy explosives mixture.

Explosives or blasting agents are classified by their propagation velocity (rate of reaction) and ability to be used in holes containing water. Manon (1976) provides additional information on the background and use of explosives in mining.

Propagation is the rate at which the reaction progresses throught the explosive material. The propagation velocity is a measure of explosive energy when applied to a specific explosive. A slurry, for example, can be formulated to provide a given propagation velocity at a specified energy level, then reformulated to alter the propagation velocity to better match fixed blasting requirements without affecting the total available energy. A reduction in the propagation velocity will spread the available energy over a longer detonation time, effectively reducing the peak shock energy and allowing a longer period for generation of the gas effect. Increasing the propagation velocity would have the opposite effect. In this case, the peak energy is relative to the propagation velocity.

The primary mechanism of explosives is the rapid expansion of gases in a confined space. When the explosion is initiated, the detonation releases a shock wave into the rock mass, creating both macro- and microcracks. The process of detonation--i.e., an exothermic chemical reaction proceeding to equilibrium at a lower energy state--releases a tremendous amount of heat in a short time. The reaction, generally rapid oxidation, produces a substantial volume of gas. The rapid generation of gases in a microsecond produces a substantial pressure. This gas pressure pervades the previously generated cracks and causes them to propagate rapidly. As the gas expands, generally at a higher rate than the crack propagation, it provides a lifting action to the fragmented rock, normally moving the rock away from the newly created face. Thus, blast hole pressure or gas effect provides some additional fragmentation but primarily produces the lifting and movement required for a successful multiple hole blast pattern. A proper selection of delays will enhance this gas effect in a blast.

Types of Explosives

The term "explosives" as used in this paper refers to both blasting agents and explosives. Technically, blasting agents are materials that cannot be detonated by a blasting cap. Explosives can be detonated by a blasting cap. ANFO, a mixture of ammonium nitrate fertilizer and approximately 6 percent fuel oil, is a blasting agent widely used by coal mines. Dynamite is an example of an explosive. Due to a combination of cost and safety factors, blasting agents make up a high percentage of the explosives used at coal mines. A small charge of true explosive is set in each hole containing the blasting agent (Fig. 1) to initiate the explosive reaction of the blasting agent.

ANFO

The type of explosive used most commonly in Western coal mines is based on ammonium nitrate or a related oxidizer and a fuel, such as oil, powdered aluminium, or coal. This combination, commonly called ANFO (ammonum nitrate fuel oil), consists of high-grade ammonium nitrate formed in prills and impregnated with approximately 6 percent fuel oil by weight.

At the point of maximum propagation, ANFO will react at 9,000 to 12,000 feet per second. With the addition of up to 6 percent paint grade aluminum, the reaction rate can be increased to nearly 14,000 feet per second. ANFO is a low-cost blasting agent and has been used sucessfully in a number of mining applications. It has the drawback of being water soluble and, when in solution, being chemically inert as a blasting agent.

The relatively slow reaction time for ANFO, coupled with the chemical constituents in the reaction, result in the generation of a small, sustained release of shock energy. However, the reaction generates a considerable gas effect, providing some secondary breakage and good movement within the blasted material. To gain the full effect of the blast, it is necessary to stem or fill the top third of the blast hole with coarse aggregate. The gas effect energy otherwise would vent to the atmosphere and minimize the secondary fragmentation and the movement of the blasted material.

ANFO has been used successfully to fragment plastic-acting rock, such as limestone and sandstone, where the energy-absorbing quality of the rock requires an initial shock wave to propagate fractures and a significant gas effect to both continue the fragmentation process and to lift the blasted material. The lower velocity, slower energy release of ANFO is ideally suited to these plastic rock types.

Rocks generally classified as elastic have also been successfully fragmented using ANFO. Application to elastic-type rocks must be undertaken with caution, however. Using ANFO to fragment massive granites of high compressive strength generally requires an abnormal number of blast holes loaded to excessive powder factors. There is a tendency of ANFO to "rifle" or vent up the blast hole to the atmosphere when used to fragment massive and competent elastic-type rocks, and fragmentation can be unsatisfactory. ANFO does work very well on highly structured (faulted, jointed, fissured) elastic rocks where fragmentation is of lesser concern than movement or loosening of the material.

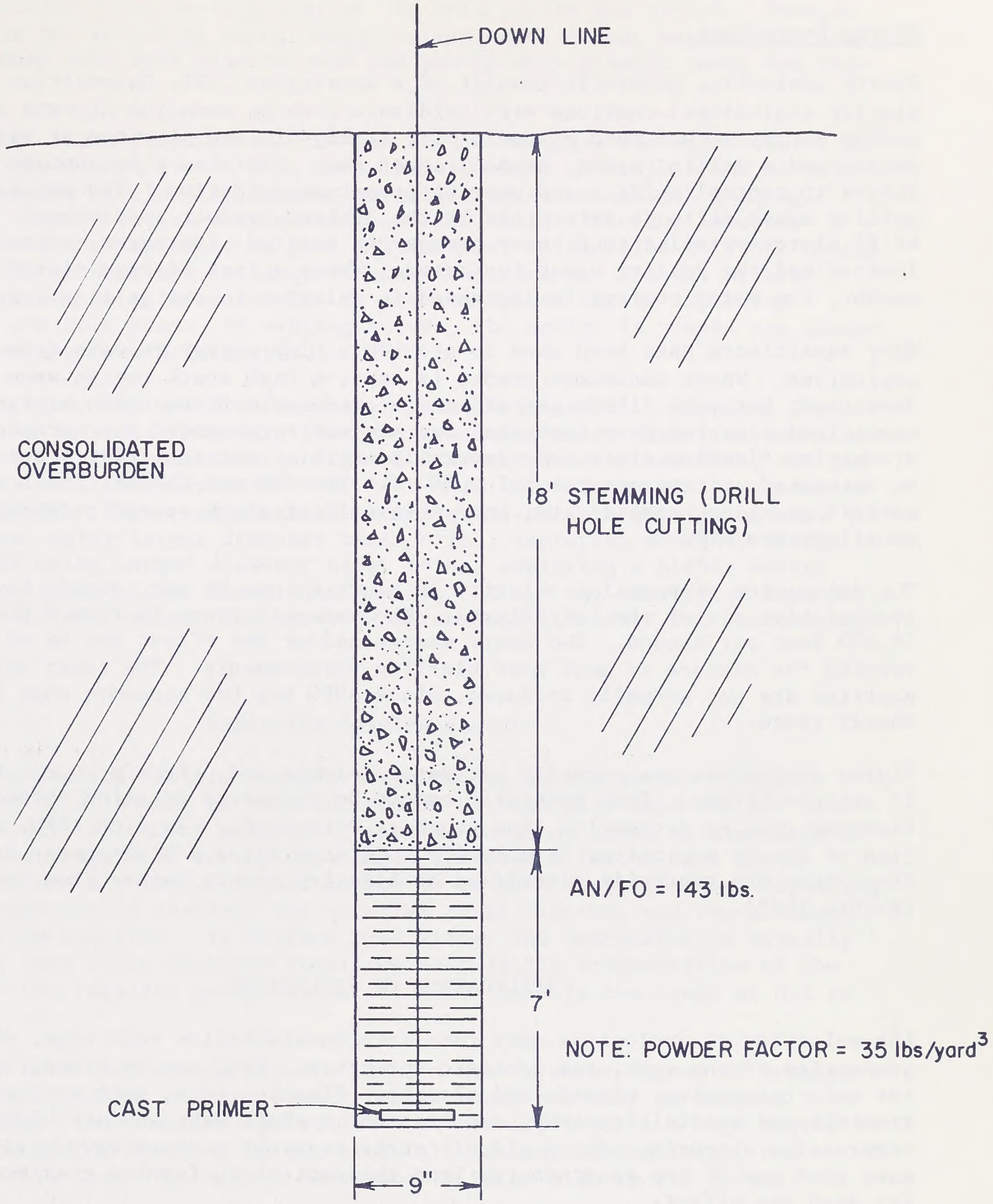

DOWN LINE
CONSOLIDATED OVERBURDEN
18' STEMMING (DRILL HOLE CUTTING)
AN/FO = 143 lbs.
7'
NOTE: POWDER FACTOR = 35 lbs/yard³
CAST PRIMER
9"

Figure 1.

CROSS SECTION - TYPICAL 25' BLASTHOLE IN CONSOLIDATED OVERBURDEN

Slurry Explosives

Slurry explosives generally consist of a sensitizer (TNT, Composition B, or similar explosives) combined with oxidizers such as ammonium nitrate and sodium nitrate; fuel such as coal, oil, finely divided aluminum or magnesium; water; and a gelling agent, normally guar gum. Slurries also contain stabilizers to control acidity and prevent premature oxidation. The water/gelling agent ratio is determined by the desired product consistency. Where a stiff slurry--similar to a heavy grease--is desired, the water content is lowered and the gelling agent increased. Where a less viscous slurry is sought, the water content is increased in relation to the gelling agent.

Many sensitizers have been used to provide a high-energy release from slurry explosives. Where smokeless powder is used, a high shock energy wave is developed, but very little gas effect is produced. Nitro carbo nitrate (NCN) sensitized slurries have been used but are not recommended for surface production blasting since they generally exhibit poor sensitivity and cannot be detonated at temperatures below 20° F. The TNT and Composition B slurries exhibit excellent sensitivity, good to excellent shock energy release, and excellent gas effect.

The detonation propagation velocity of slurries can be set, within bounds, by the relative mix of the ingredients. The velocity range is from 9,000 to 16,000 feet per second. The shock energy and/or gas effect can be adjusted by varying the mixture to meet most blasting requirements. The lower velocity slurries are not normally produced, since ANFO has the economic edge in this energy range.

Slurry explosives are normally not water soluble and, therefore, can be used in wet conditions. They generally cannot be detonated by using either blasting caps or detonating line (such as Primacord). As with ANFO, detonation of slurry explosives is normally initiated using a high-energy booster; thus, they are generally classified as blasting agents rather than explosives (Buchta 1972).

APPLICATION OF EXPLOSIVES

The selection of explosives must take into consideration rock type, physical properties of the rock, and geologic structure. Rock can be classified into two main categories, elastic and plastic. Elastic rocks, such as typical granitic and quartzitic rocks, can transmit a shock wave and are high in compressive strength. Since elastic rocks transmit a shock wave well, they make good use of the shock energy from the explosive, forming cracks suitable for good gas effect.

Plastic rocks are those which are relatively low in compressive strength and absorb shock energy rather well, thereby making poor use of the shock energy by not developing an extensive cracked zone for the gas effect. Rocks of this type are usually softer materials such as shale, limestone, and sandstone. For the most part, the shock energy part of the explosive reaction is wasted in plastic-acting rock, leaving most of the work to the gas effect. Because this ratio of gas effect to shock energy varies in different explosives, some explosives work well with elastic rock and poorly with plastic rock, and vice versa.

In addition to crack propagation, the gas effect provides the major source of movement of the broken rock. Some rocks have so many natural planes of weakness they require little displacement to effect excellent shovel loading. Other rocks require severe displacement to facilitate efficient removal. Several factors are important to good displacement in addition to shock energy breakage. The primary one is adequate mass confinement. The gas effect energy should not be allowed to vent to the atmosphere before imparting movement to the rock mass. If venting occurs, the energy is wasted and damage from the airblast is a possibility.

On the other hand, too much confinement is also detrimental. Assuming the rock is broken in place, the only function remaining is to impart movement or displacement. If the explosive in a given diameter hole is too deep, the gas effect energy used for displacement or lift will be overcome by the excessive mass to be moved. This condition can be prevented through developing shallower benches, using larger diameter blast holes, employing a higher energy explosive, or using larger diameter blast holes, employing a higher energy explosive, or using closer blast hole spacing. Since the density or mass per unit volume of rock varies, the above adjustments will differ for various rock types.

Explosive Loading Factors

The explosive loading factor, commonly referred to as the powder factor, expresses the relationship between the pounds of explosive used and the bank cubic yards (bcy, volume of material measured, in-situ, prior to blasting) of material to be fragmented during blasting. The powder factor used in any given application may vary from 0.2 lb/bcy to as much as 2.0 lb/bcy, depending upon the fragmentation desired, the material to be blasted, and the movement or distribution required. In surface coal mines, the overburden is normally loaded using very large machines requiring very little fragmentation of the material, so the required powder factor is quite low--in the range of 0.2 to 0.5 lb/bcy.

In quarry or hard-rock mining applications, a much greater degree of fragmentation may be required, and the powder factor would normally be between 0.5 and 1.0 lb/bcy. Construction operations occasionally require a high degree of fragmentation and/or movement of the material blasted; consequently, the powder factor in these operations occasionally is as high as 2.0 lb/bcy.

A technique known as overburden casting has been increasingly used in recent years. With this technique, the overburden is actually moved over some distance using explosives. In certain applications, as much as 50 percent of the in-place overburden may be moved into a previous open-cut by the blast. This technique requires not only specialized delay of the blasting, but extremely high powder factors, which result in a larger amount of flyrock and fugitive dust. This technique, which is occasionally economically viable, may have adverse environmental impacts and should not be used except in special situations and remote locations.

The loading equipment to be employed in the mining operation is usually the determining factor in the design of the blast. If the material is to be moved with front-end loaders, the mine operator would prefer that the material be well-fragmented and scattered over an area roughly twice the size of the original in-place rock. This results in a pile of broken material which is approximately half the height of the working face. The powder factor in this operation would usually be between 0.5 and 1.0 lb/bcy.

If the mining operation employs a large diesel or electric shovel for digging, the operator would prefer that the material be highly fragmented, but with very little movement of the in-place material. The operator would dictate a blasting design that would fragment the material, but leave it stacked in-place. A powder factor of 0.4 to 0.6 lb/bcy might be employed.

In large, high-production surface coal mines, common in Colorado, Montana, North Dakota, and Wyoming, overburden movement is generally accomplished using either large digging shovels or draglines. In blasting for a dragline operation, very little movement or fragmentation of the material is required. The blast would normally be designed with a low powder factor, a high degree of stemming, and probably a buffer of blasted rock surrounding the area so that the blast is well confined and the overburden is broken without any movement of the in-place material. This is done so that the dragline may sit on the blasted rock while it is digging. This type of blasting results in the least environmental impact. The powder factor, between 0.2 and 0.5 lb/bcy, should not cause any structural cracking outside the immediate blasting area and should cause little interference with aquifers below the blasting horizon. Stemming generally fills at least 50 percent of the hole, so there is little, if any, flyrock or fugitive dust generated by the blast.

Explosive loading factors can be figured using a simple calculation. For example, a blast pattern consisting of 20 holes, each loaded with 400 pounds of explosives and designed to fragment a total 10,000 bank cubic yards of rock, would have a powder factor of 0.8 lb/bcy, or 0.8:

$$\frac{400 \text{ lb} \times 20}{10{,}000 \text{ bcy}} = 0.8$$

A reduction in the total explosives used in the example cited would result in a lower powder factor. Reducing the individual hole loading to 200 pounds of explosive, leaving the other conditions as stated, would result in a powder factor of 0.4 lb/bcy. This factor is considered a reasonable average powder factor for layered shale and sandstone overburdens prevalent in the western United States (Du Pont 1978).

A third factor, the depth of the blast hole, can also influence powder factor, fragmentation, and level of transmitted vibration. For example, a large diameter (10- to 12-in.) blast hole 60 to 70 feet in depth would be too shallow to be effective if charged with a high-density, high-velocity explosive. The explosive charge, within the constraints of a reasonable powder factor, would be in the bottom 20 percent of the hole. Fragmentation of the upper strata in the hole would be limited to heave, or flexure, as gas pressure generated during the blast dissipated and expanded into the fragmented lower strata creating lift in the upper strata. Tests have demonstrated that the maximum direction of peak pressure loading of the adjacent rock is perpendicular to the major axis of the blast hole and adjacent to the explosive charge (Cook 1974).

There are two solutions available where a high density-high velocity explosive must be used. Using either smaller diameter holes on closer spacings (allowing a higher explosive column) or decking of the explosive charge alleviates the problem of low fragmentation near the top of the hole. Decking (i.e., layers of explosives separated by inert material) provides a considerable advantage, in that the explosive charge can be located at optimum intervals for fragmenting more resistant layers in the rock. The use of smaller holes on closer spacings can provide better overall blast control but is less economical in application.

Delay Detonation

Multiple blast holes are used to ensure fragmentation in large production blasts. The geometry of a blast is three dimensional, including height, width, and length. A normal production blast consisting of multiple blast holes must be designed with consideration for the constraints of hole diameter, burden, hole depth, and powder factor as discussed.

One of the parameters which governs the environmental impact from a blast is the amount of explosives detonated at any given instant. This parameter determines not only the amount and velocity of ground movement generated by the blast, but also the airblast and the way the blast is perceived by those in the vicinity. This is the reason for the development of delay detonation in which a large blast is accomplished in a very short time by detonating small amounts of explosives in a predetermined pattern and delay sequence. This delay in the blast pattern is generally accomplished using delay initiators such as blasting caps, or by using delay devices such as connectors, in a detonating cord arrangement. In additon, delay detonation has been improved recently though the development of a sequential blasting machine.

Sequential blasting machines are used only in conjunction with electric blasting caps. Rather than relying on delays which are built into the cap, the machine initiates the caps sequentially so that the delay occurs in the machine, rather than in the initiating device. Using a sequential blaster, a single delay period of electric caps may be used to initiate the entire blast, but by connecting to the machine, delay intervals as small as one millisecond are possible and a much wider range of delay intervals is available. This results in very small amount of explosives being initiated at any given instant; consequently, the resulting ground movement and airblast are greatly reduced, even for large blasts.

The use of millisecond delays has both advantages and disadvantages in providing fragmentaiton, as shown in Figure 2. If the first row of holes is fired and the second row delayed, cracks furnish reflective faces for tensile slabbing from the second row of holes, and so forth. The degree to which fragmentation or breakage is improved is questionable, however. The real value of delays is better displacement through reducing the rock mass effect by allowing the gas expansion from the first row to start rock movement ahead of firing the second row. The effectiveness of this movement, however, decreases as rows are added, since delay periods are too short to be effective four or five rows into the blast, and long delay periods cannot be effectively used because of cut-off (interruption of the explosive column).

Delays can also be used to change hole spacing and burden ratios, even though the blast holes are spaced equally. Figure 3 deomonstrates the effective 28-foot spacings and 14-foot burdens developed by the echelon delay system (the holes are detonated on diagonals of the rectangular drill pattern, or on a series of off-sets) to allow the gas effect of the explosive to do more work by reducing the burden it has to work against, even though the blast hole spacing remains constant and equal.

The loss of fragmentation through the use of delays could be significant, especially in hard, elastic rock. If there are two blast holes or rows of holes delayed by 17 milliseconds, and the rows are 20 feet apart (Fig. 4), the shock strain has moved well past the second row of holes before the second row is initiated. The impact of blasting hole spacing and delay period on reducing or reinforcing the peak shock wave generated by the blasting event is discussed by Linehan and Wiss (1982).

If instantaneous initiation is used (Fig. 5), there will be a collision of shock fronts, which will (theoretically) furnish improved fragmentation at the midpoint between holes. This system takes maximum advantage of the shock energy to promote fragmentation (Grant 1969). A problem in using instantaneous blast hole initiation requires consideration. Even though the pounds of explosive per bank cubic yard do not vary, the total single point energy released through instantaneous blasting becomes the multiple of all holes included within the blast. This aggregate, concurrent release of energy will generate a maximum shock strain that will be transmitted through the rock strata, creating "ground shock" conditions that can damage civil structures.

A major advantage in using delay detonation is the reduction in total energy released for a given instant in time, thus controlling the total shock strain in a given instant, reducing the potential for damage to civil structures and excessive flyrock.

Blast Hole Loading Factors

The typical blast hole loads addressed below reflect conditions common to successful blasting of limestone, sandstone, and shale overburden in surface mines in the Western United States. Because of conditions unique to specific

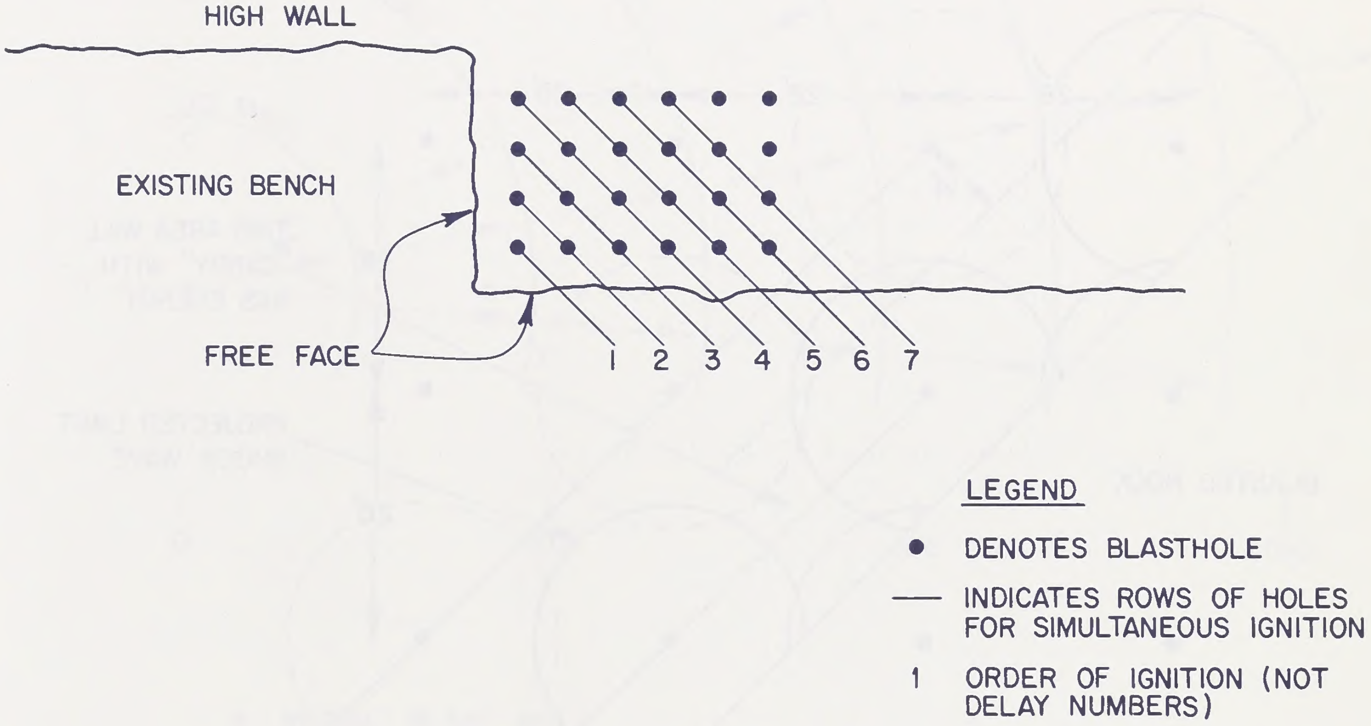

HIGH WALL
EXISTING BENCH
FREE FACE
1
2
3
4
5
6
7
LEGEND
● DENOTES BLASTHOLE
— INDICATES ROWS OF HOLES FOR SIMULTANEOUS IGNITION
1 ORDER OF IGNITION (NOT DELAY NUMBERS)

Figure 2.

USING MILLISECOND DELAYS IN A BLAST PATTERN
PLAN VIEW

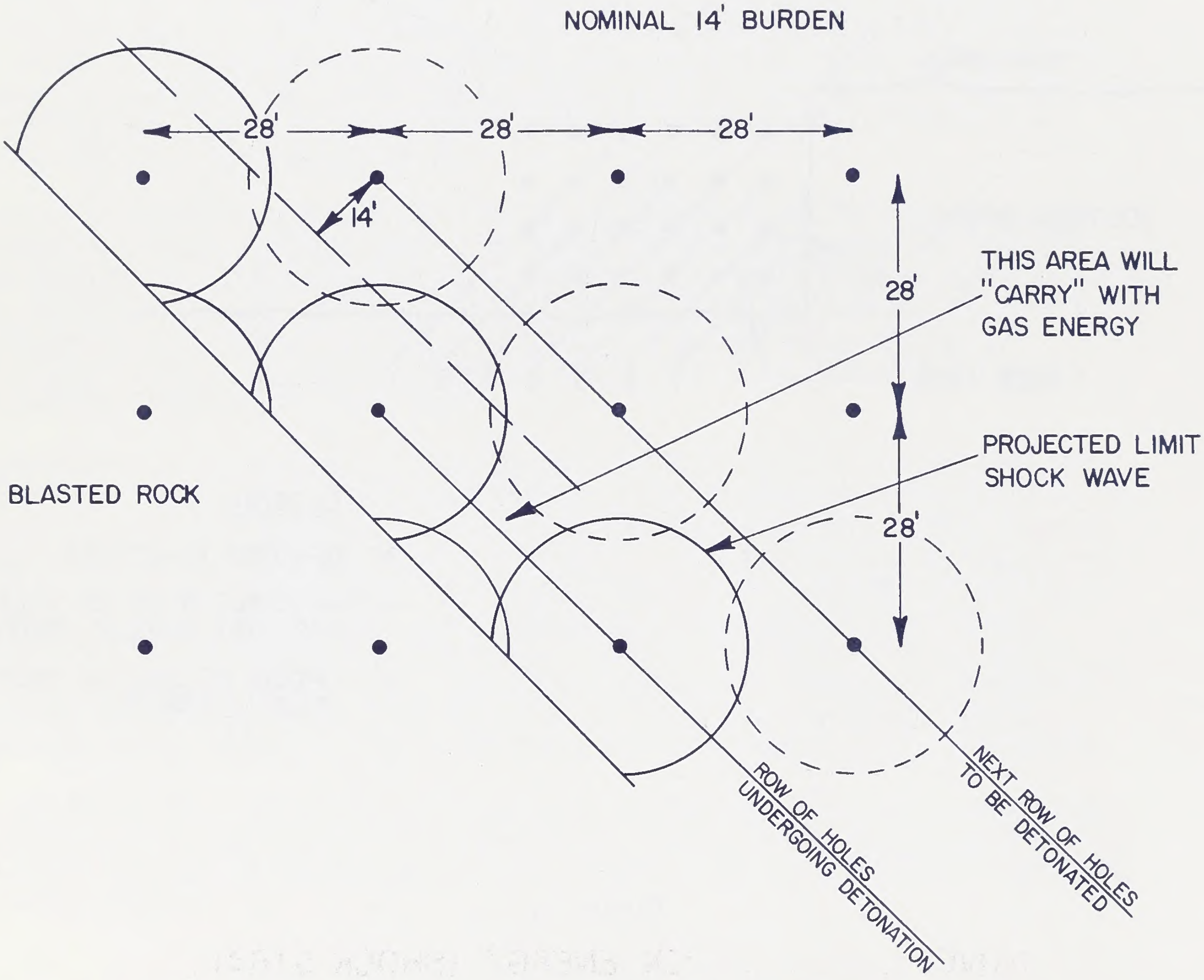

NOMINAL 14' BURDEN
28'
28'
28'
14'
28'
28'
THIS AREA WILL "CARRY" WITH GAS ENERGY
PROJECTED LIMIT SHOCK WAVE
BLASTED ROCK
ROW OF HOLES UNDERGOING DETONATION
NEXT ROW OF HOLES TO BE DETONATED

Figure 3.

REDUCTION IN BURDEN USING ECHELON DELAY PATTERN

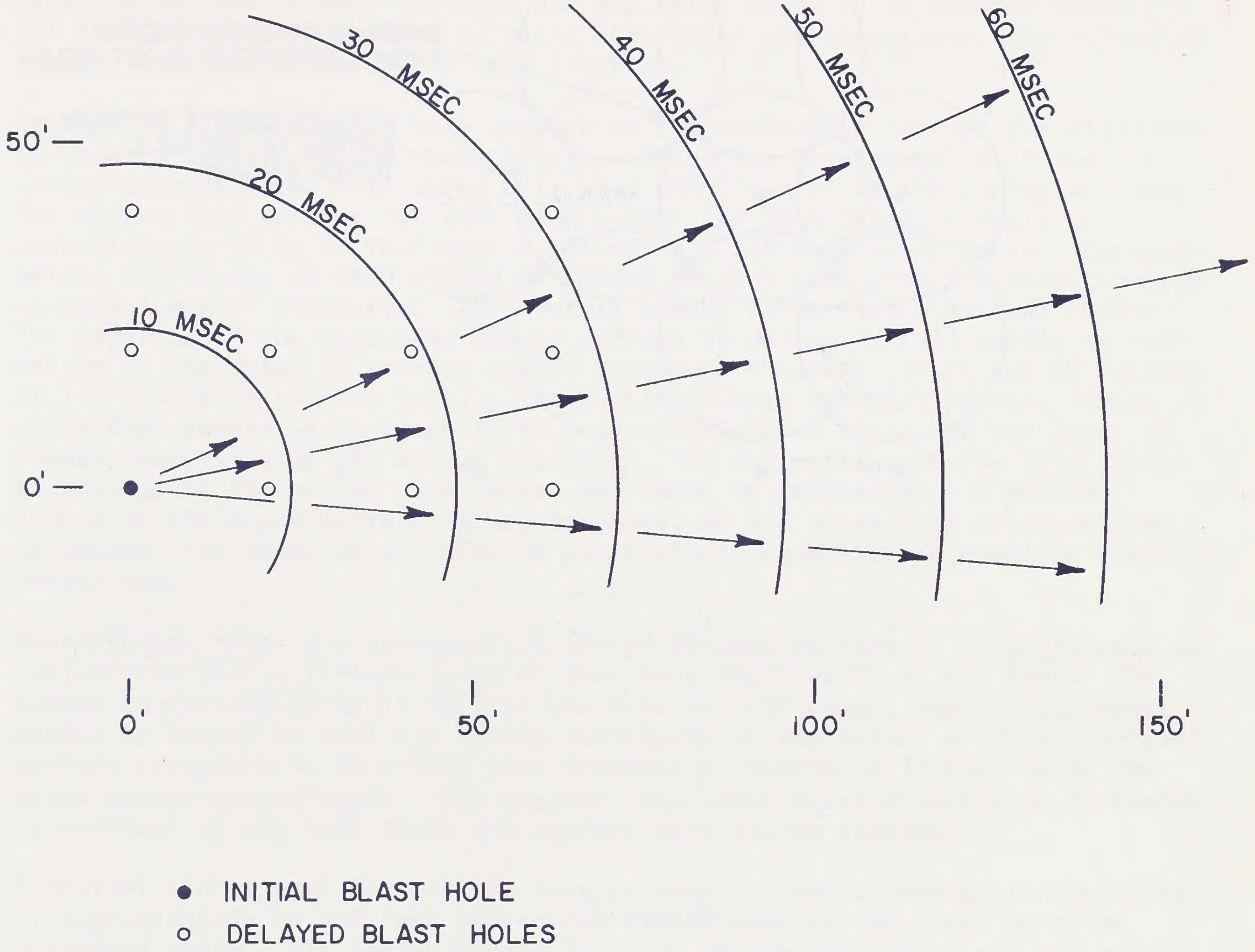


Figure 4.

MOVEMENT OF SHOCK ENERGY (SHOCK STRAIN) FROM BLAST HOLE PER MILLISECOND OF DELAY

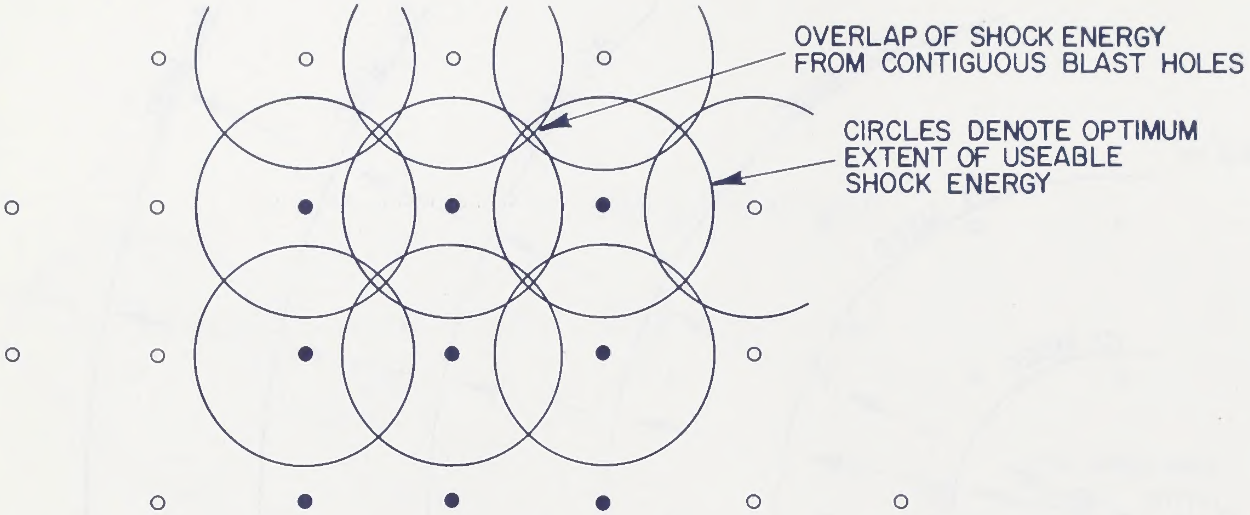

OVERLAP OF SHOCK ENERGY FROM CONTIGUOUS BLAST HOLES
CIRCLES DENOTE OPTIMUM EXTENT OF USEABLE SHOCK ENERGY

Figure 5.

OVERLAP OF SHOCK ENERGY WHERE INSTANTANEOUS IGNITION OF ALL HOLES IS USED explosives applications, blast hole diameters, spacings, depths, explosives loading, powder factor, and other factors, the examples presented here must be considered as guidelines rather than absolute solutions to blasting application problems.

Blasting of overburden for removal from a surface mineable coal seam is a straightforward operation. The variability of rock conditions will dictate minor variations in hole spacings and explosive loads in an ongoing operation. For in-place overburden with no major structural considerations, the following example outlines normal blast hole loadings.

Typically, a square blast hole pattern is the easiest to lay out the drill and provides a uniform burden to each hole. Where the hole depth is 70 feet, a 10-5/8-inch-diameter hole works well when ANFO is used as the explosive load. The normal hole spacing for that bank height and hole diameter would be approximately 28 by 28 feet with a volume of 2,320 bank cubic yards. Approximately 750 pounds of ANFO should be loaded in each hole with a 2-pound booster in each layer of explosive. The overall powder factor would be 0.32 lb/bcy. The layering of the explosive should include 50 percent or 375 pounds in the bottom of the hole; 30 percent or 225 pounds in the next layer; and 20 percent or 150 pounds in the top layer. The decking (inert material between layers of explosive) should be in equal lifts and sufficient to bring the top layer of powder two-thirds of the way up the hole. The top portion of the hole should be stemmed to the collar with coarse aggregate or equivalent. A general layout of the blast pattern is not included, as the detonation sequence (use of delays) for each row of holes is particularly sensitive to specific site conditions.

Where deeper holes are necessary, a 30- by 30-foot pattern is normally used in conjunction with a 15-inch diameter hole to a depth of 90 to 100 feet. The powder factor should still fall in the 0.30 to 0.50 range, and the explosive should be decked to fill the bottom two-thirds of the hole. A 12- by 12-foot pattern can use a 4- to 6-inch hole diameter to depths of 35 feet using the given powder factor range. The smaller, shallower holes should only be loaded to one-half of the hole depth and stemmed with coarse aggregate.

A typical slurry explosive with a density near 1.2 and a propagation velocity of approximately 14,000 feet per second can be used in the blast patterns discussed above. The powder factor does not change and the slurry effectively fragments the rock with excessive shock energy in lieu of the gas effect generated by ANFO. The requirements for column rise of explosive, decking, and stemming remain unchanged from the examples cited for ANFO. The detonation sequence should be adjusted to site-specific conditions.

Optimum Blasting

When designing a blast, a blast hole should be first viewed in its entirety to optimize results. Bench heights, hole diameter, types of explosives, rock types and conditions, and other factors should all be considered in selecting the design. Once this is accomplished, fragmentation, blast vibrations, and flyrock control through the use of proper delays and stemming can be optimized.

Fragmentation is the result of energy input, its distribution, and efficient use of both shock and gas effect. Because energy decays at the periphery of a blast, fragmentation tends to be poorer at the periphery. This effect can be minimized in two ways. One method is to blast as close to a square pattern as possible. In a 20-foot by 80-foot rectangle there are 1,600 square feet of area and 200 feet of perimeter. If a square 40-feet by 40-feet is used, there are still 1,600 square feet of surface area, but only 160 feet of perimeter. Thus, the perimeter is reduced by 20 percent.

A second method to reduce the perimeter is to make the blast as large as possible. In the 40-foot by 40-foot example (1,600 square feet of area and 160 feet of perimeter), the area to perimeter ratio is 10:1. In a square pattern 80 by 80 feet, there are 6,400 square feet of area and 320 feet of perimeter, yielding a ratio of 20:1. Keeping this ratio as high as possible will reduce the poorly fragmented zone in the blast.

Good blasting results depend on the efficient transfer of explosive energy (both shock and gas effect) to the rock mass. The manner in which different explosives deliver their energy, however, varies significantly from one commercial explosive to another; moreover, the transfer differs for a given explosive to another; moreover, the transfer differs for a given explosive acting on different rocks. A high-energy slurry delivers its energy through a substantial peak pressure or shock followed by a brief gas effect as the gases expand. ANFO, conversely, applies a very low peak pressure or shock but an extended peak gas effect. Within these extremes, an explosive can be selected with characteristics to best match a specific condition (Buchta 1972).

To recap, the energy characteristics of an explosive do not when properly used create a condition where structural damage, flyrock, airblast or other undesirable elements are an inevitable result. The energy level of an explosive is matched to the rock to achieve optimum fragmentation. The undesirable elements in blasting are controlled through proper design--i.e., selection of hole diameter, depth, and spacing, and detonation timing and sequence.

PRIMARY MECHANISMS OF IMPACT

Ground vibration and airblast are the primary causes of off-site impacts of blasting. Some residual wastes from blasting, primarily dissolved or gaseous nitrogen compounds, have a potential for causing adverse impacts but are seldom present off-site in measurable quantities. Water quality and/or soil contamination may occur due to the careless handling of explosives of their chemical components prior to their actual use in blasting.

Vibration

Earth movement or vibration is normally defined in terms of the frequency of the vibration and the peak velocity of a particle of the material (particle velocity). Figure 6 illustrates the range of frequencies and particle velocities sometimes associated with blasting. The 2 inches-per-second (ips)

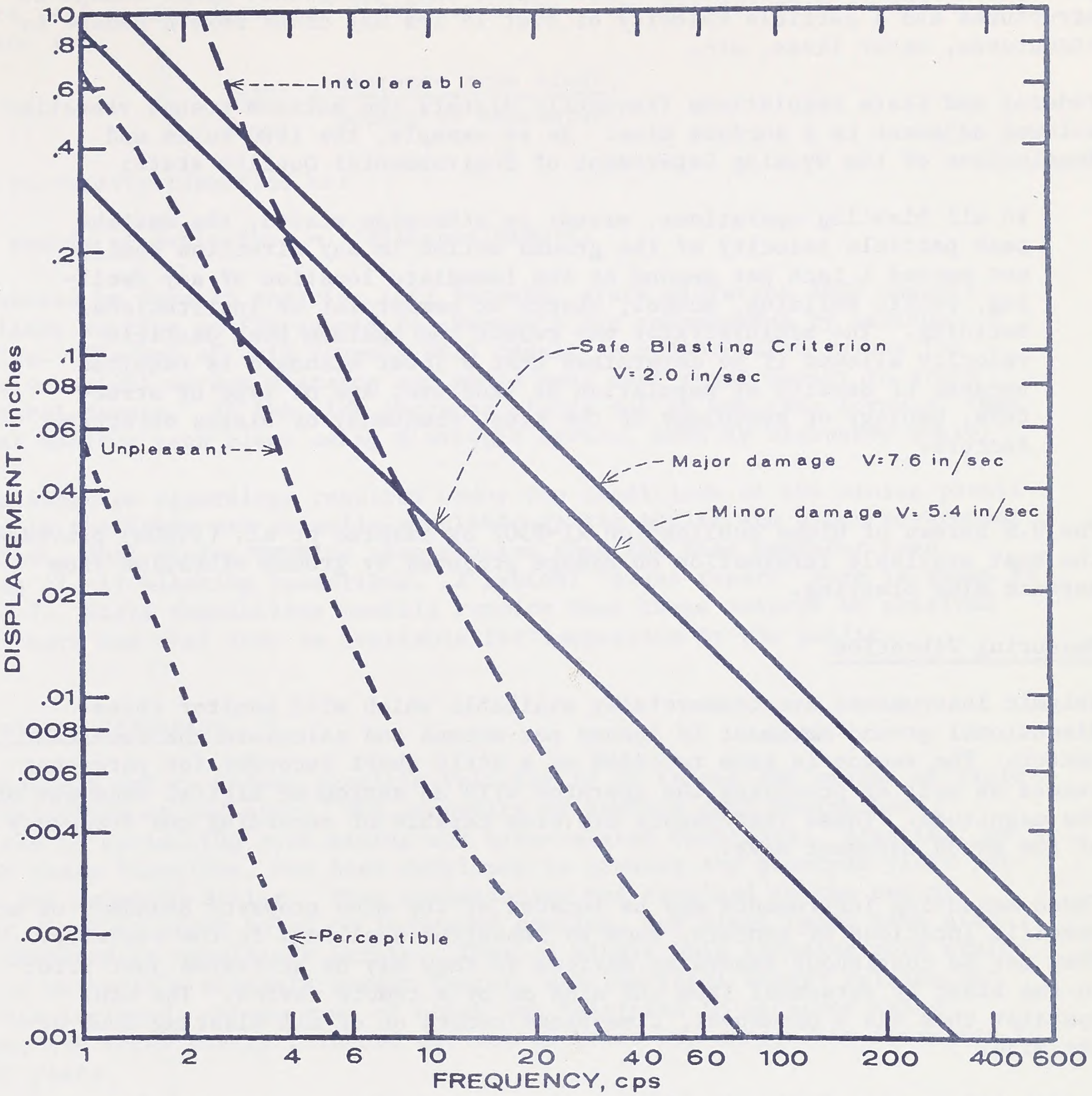


Figure 6.

HUMAN RESPONSE AND DAMAGE CRITERIA
FROM AIA, 1972

criteria for safety to structures has been questioned recently and is discussed in a later section. Older literature (Ash 1972) indicates that a peak particle velocity of under 2 ips causes only occasional minor damage to structures and a particle velocity of over 17 ips may cause severe damage to structures, water lines, etc.

Federal and State regulations frequently dictate the maximum ground vibration allowed adjacent to a surface mine. As an example, the 1980 Rules and Regulations of the Wyoming Department of Environmental Quality state:

> In all blasting operations, except as otherwise stated, the maximum peak particle velocity of the ground motion in any direction shall not exceed 1 inch per second at the immediate location of any dwelling, public building, school, church or commercial or institutional building. The administrator may reduce the maximum peak particle velocity allowed if he determines that a lower standard is required because of density of population or land use, age or type of structure, geology or hydrology of the area, frequency of blasts or other factors.

The U.S Bureau of Mines publication RI-8507 by Siskind et al. (1980b) provides the best available information on damage produced by ground vibration from surface mine blasting.

Measuring Vibration

Seismic instruments are commercially available which will monitor three-dimensional ground movement in inches per second and calculate the resultant vector. The vector is then recorded on a strip chart recorder for permanent record as well as providing the operator with an analog or digital read-out of the magnitude. These instruments are also capable of recording the frequency of the gound movement wave.

These measuring instruments may be located at the mine property boundary or at specific locations of concern, such as inhabited dwellings in the vicinity. They may be continuous recording devices or they may be activated just prior to the blast by personnel from the mine or by a remote device. The mine operator thus has a permanent, time-based record on of all blasting done at the mine.

Recent information (Medearis 1979) indicates that the measurement of ground level particle velocity may not be an appropriate indicator of the potential for damage, since most structures amplify the ground vibrations.

Should the mining operator choose not to monitor the blasting using seismic instruments as discussed here, the option is generally to use blasting criteria established by the U.S. Bureau of Mines. Tables have been developed to indicate the amount of explosive that may be instantaneously initiated without resulting in structural damage at a specific distance. The formula $W = (D/70)^2$ is normally used to define the amount of explosive, where W is the weight of explosive (in pounds) to be initiated instantaneously and D is the distance (in feet) from the nearest structure. This is a modification of the "square root scaled distance" (SRSD) equation. The general form of the equation is:

$$SSD = \frac{\text{distance from blast,}}{\text{pounds of explosive}}$$

which is readily converted to:

$$\text{pounds of explosive} = (\text{distance/SRSD})^2.$$

Care should be used in applying this formula, since different SRSD numbers (see later section on "Threshold for Damage") are recommended by various agencies. The use of this formula will result in conservative values for explosive weight versus distance and would meet most requirements to avoid structural damage. If the mine operator elects not to use this formula, then he must monitor each blast using a seismic device, such as discussed above.

The seismograph recordings required under the conditions of the mining permit issued by the State are normally available to the public and other government agencies. Coal mining permits also require that the mine operator keep records of all blasting operations. A typical "blast report" form is shown in Figure 7. State regulations usually require that these records be retained for 3 years and that they be available for inspection by the public.

Controlling Vibration

The simplest way to reduce particle velocity is to reduce the amount of explosive detonated at one time. The economics of surface coal mining have resulted in optimizing most mining and mine-related functions. Blasting, as one of these functions, has been developed to produce the greatest yield per blast and expended dollar. This optimization has resulted in the use of larger diameter blast holes on increased spacing, and blast holes have also been deepened as conditions permit. Thus, a single hole contains more explosive to maintain a workable powder factor, and the total energy release per hole has increaed. Where rows of holes are initiated in sequence using delays, the total energy released per row of holes has marginally increased in recent years.

For the most part, when production blasting occurs within 1,500 feet of civil structures, the potential for damage is substantial. Several methods are currently used to successfully control transmitted shock energy. The geometry of the blast can be changed to alleviate excessive ground vibration and potential damage to structures. As discussed earlier, a square or nearly square blast pattern (in plan view) will generally provide optimum fragmentation. However, the rows of holes that initiate in the same instant are longer, containing a larger number of blast holes with an accumulated release of energy that is the sum of all holes fired at once. Energy release

Figure 7.

BLAST REPORT

MINE:

DATE OF BLAST:

Location of Blast	
Time of Blast	
Blaster in Charge	
Blaster's License Number	
Number of Persons In Blasting Crew	
Distance to Nearest Designated Structure	
Direction of Nearest Designated Structure	
Weather Condition	
Type Material Blasted	
Burden	
Number of Holes	
Spacing of Holes	
Diameter of Holes	
Depth of Holes	
Type of Explosive Used	
Total Weight of Shot	
Type of Delay	
Method of Firing	
Type of Circuit	
Maximum Number of Holes Per 8ms Period	
Maximum Weight of Explosives Per 8ms Period	
Type of Stemming	
Matting or Other Flyrock Protection	
Seismograph Information (If Required)	
Reading of Seismograph	
Location of Seismograph	
Distance From Blast	
Type of Instrument	
Name of Operator	
Name of Person Analyzing Seismograph Record	
Signature of Blaster in Charge	

Blaster's Sketch of Blast Pattern

SAMPLE BLAST REPORT

DRAWN BY:	DATE	SCALE:	EXHIBIT NO.
APP'D BY:		DATE:	MP-37
DESIGN BY:	DATE	DWG. NO.:	
APP'D BY:			

MORRISON-KNUDSEN COMPANY, INC.
MINING GROUP/ BOISE, IDAHO

can be reduced by using a narrow, rectangular blast pattern initiated on a delay sequence, although this sacrifices some efficiency and fragmentation (Fig. 8).

Another common method for mitigating ground vibration is to use smaller diameter blast holes on closer spacings--generally with reduced size blast patterns--to reduce the energy release in a given instant. Also, instead of fragmenting a 70-foot-high bench in a single blast, the blast height can be reduced to 35 feet to achieve the vertical fragmentation and control vibration. This last method is costly, as shovels and trucks must be moved in to excavate the first blast, moved out, then moved in again to excavate the second bench cut to reach the 70-foot total bench.

In rare instances, these methods are not effective in reducing ground vibration and the reduction in energy released at a given point in time actually will cause an increase in the measured transmitted shock. The increased shock is normally the result of geologic conditions and usually occurs in rock that is massive--i.e., that has very few major joints or cracks and the joints and cracks present are "tight" with good rock to rock contact. With no open geologic structure, there are few openings or faces to enhance decay of the transmitted shock wave, and the shock wave is transmitted up to 1 mile. When a reduction in the energy released causes an increase in shock wave-induced vibration, it is usually due to this condition of minimum geologic structure and the resultant harmonic frequency within the rock.

Linehan and Wiss (1982) have summarized the procedures to minimize seismic vibration as follows:

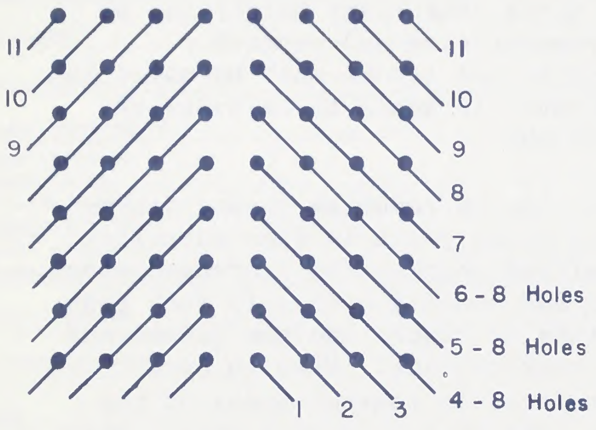
* Minimize the maximum explosive weight per delay.
* Avoid short delay intervals.
* Delay intervals of 17 ms or more to minimize any increase in vibration (phasing) with direction.
* Select spacing of blast holes, delay intervals, and sequence of firing to avoid reinforcing (the vibration) in critical directions.

Their work indicates that the last procedure may be more critical than is apparent from other literature on blasting. They found that the spacing, firing sequence, orientation, etc. of the blast holes could change seismic and airblast values by as much as six times.

Airblast and Noise

Airblast and noise are related to the airborne shock waves from the blast. For convenience of discussion, we will define noise as pertaining to those frequencies (roughly 20 to 20,000 Hz) the human ear is sensitive to and equate airblast with the concussion or overpressure effect.

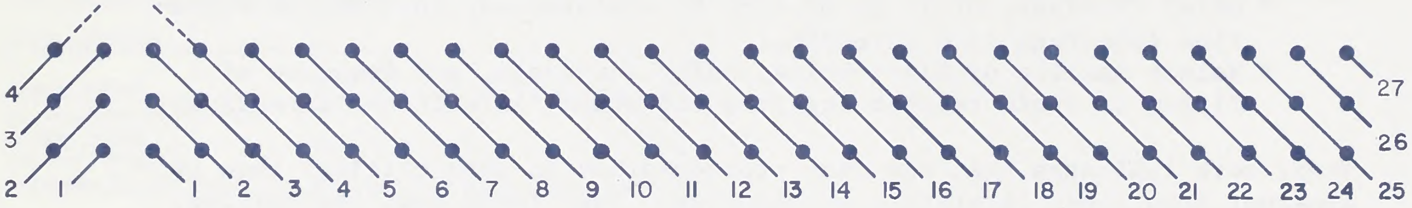
Data on airblast and noise are normally presented in terms of decibels (dB) but are sometimes presented as pounds-per-square-inch pressure. Figure 9 provides a general reference for the dB scale. The safe maximum off-site



SQUARE BLAST PATTERN SHOWING MAXIMUM NUMBER OF BLAST HOLES PER DELAY

-TOTAL HOLES IS 81-

NOTE: IN BOTH SQUARE AND RECTANGULAR PATTERNS THE ASSUMPTION IS MADE THAT HOLE DEPTHS AND DIAMETERS ARE IDENTICAL, AND THAT THE POWDER FACTORS ARE THE SAME. ALSO, THE TOTAL VOLUME OF ROCK BLASTED IS THE SAME IN EACH PATTERN.



RECTANGULAR PATTERN - EXTREME EXAMPLE TO DEMONSTRATE THE REDUCTION IN BLAST HOLES PER DELAY -TOTAL HOLES IS 81-

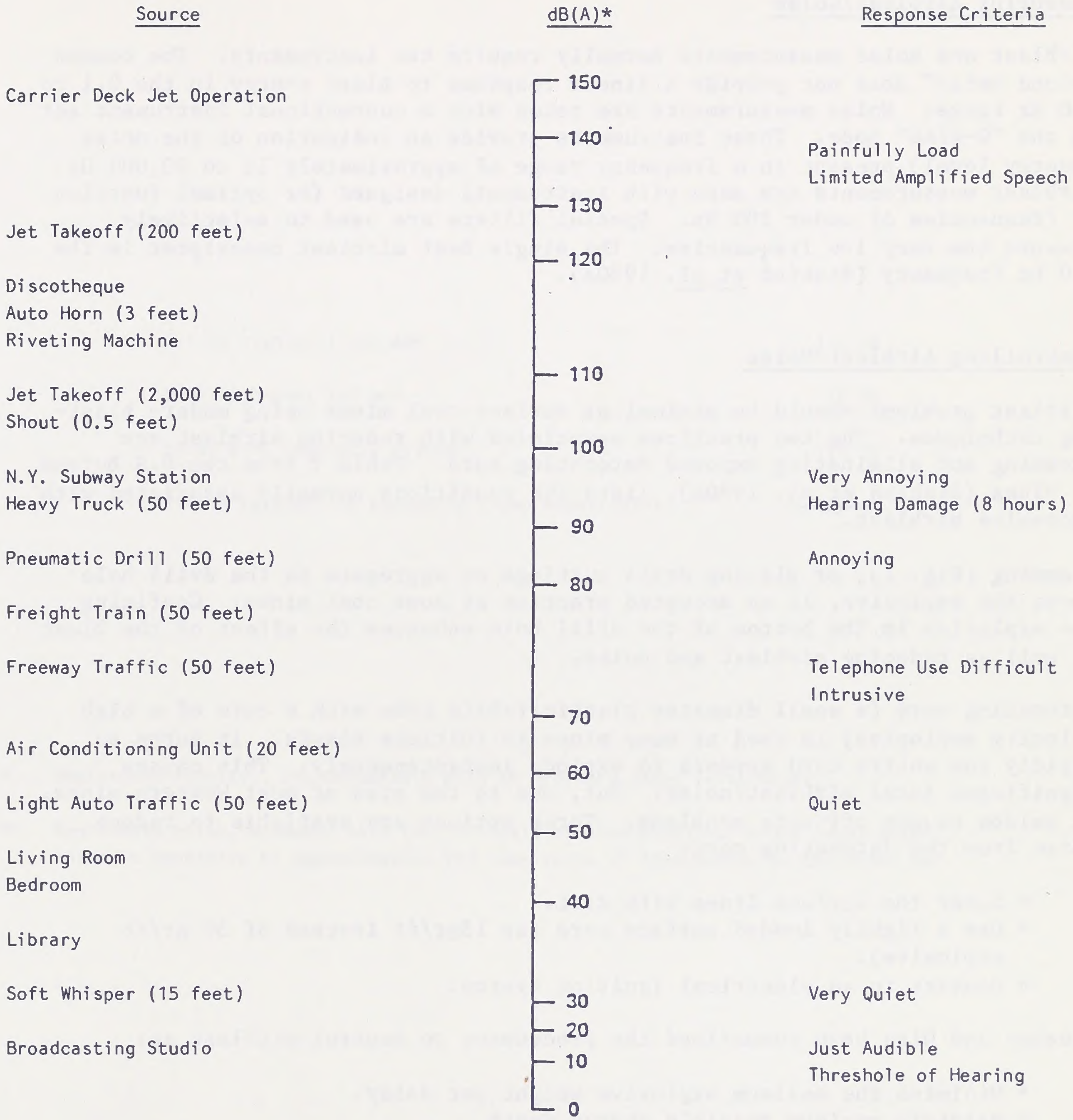
THE MAXIMUM HOLES PER DELAY IN THE RECTANGULAR PATTERN IS DELAY 4 WITH 5 HOLES (A SINGLE OCCURENCE). THE LARGER NUMBER OF DELAYS INITIATE ONLY 3 HOLES EACH.

COMPARISON OF BLASTHOLES INITIATED PER DELAY IN SQUARE AND RECTANGULAR BLAST PATTERNS

Figure 8.

Figure 9.

TYPICAL "A" WEIGHTED SOUND LEVELS
AND HUMAN RESPONSE



*Typical A-Weighted sound levels taken with a sound level meter and expressed as decibels on the scale. The "A" scale approximates the frequency response of the human ear.

Source: Environmental Quality -- The First Annual Report of the Council on Environmental Quality. Transmitted to Congress, August 1970.

noise level for blasting is 105 dB (Siskind _et al_. 1980a) in the frequency range people interpret as sound. At lower frequencies (0.1 to 5 Hz), the maximum safe off-site level is 129 to 134 dB (Table 1). The U.S. Bureau of Mines publication by Siskind _et al_. (1980a) provides the best available information on damage produced by airblast from surface mining.

Measuring Airblast/Noise

Airblast and noise measurements normally require two instruments. The common "sound meter" does not provide a linear response to blast energy in the 0.1 to 5.0 Hz range. Noise measurements are taken with a conventional instrument set in the "C-slow" mode. These instruments provide an indication of the noise (energy level) present in a frequency range of approximately 16 to 20,000 Hz. Airblast measurements are made with instruments designed for optimal function at frequencies of under 200 Hz. Special filters are used to selectively measure the very low frequencies. The single best airblast descriptor is the 2.0 Hz frequency (Siskind _et al_. 1980a).

Controlling Airblast/Noise

Airblast problems should be minimal at surface coal mines using modern blasting techniques. The two practices associated with reducing airblast are stemming and eliminating exposed detonating cord. Table 2 from the U.S Bureau of Mines (Siskind _et al_. 1980a), lists the conditions normally associated with excessive airblast.

Stemming (Fig. 1), or placing drill cuttings or aggregate in the drill hole above the explosive, is an accepted practice at most coal mines. Confining the explosive in the bottom of the drill hole enhances the effect of the blast as well as reducing airblast and noise.

Detonating cord (a small diameter plastic/fabric tube with a core of a high velocity explosive) is used at many mines to initiate blasts. It burns so rapidly the entire cord appears to explode instantaneously. This causes significant local airblast/noise. But, due to the size of most Western mines, it seldom causes off-site problems. Three options are available to reduce noise from the detonating cord:

* Cover the surface lines with dirt.
* Use a lightly loaded surface cord (as 18gr/ft instead of 50 gr/ft explosive).
* Convert to an electrical ignition system.

Linehan and Wiss have summarized the procedures to control airblast as:

* Minimize the maximum explosive weight per delay.
* Maintain maximum possible charge depth.
* Select spacing and burden of blast holes, delay intervals and firing sequence to avoid reinforcing (airblast) in critical directions.

TABLE 1.

SAFE MAXIMUM AIRBLAST LEVELS.

0.1-Hz high-pass system*	134 dB
2-Hz high-pass system*	133 dB
5- or 6-Hz high-pass system	129 dB
C-slow (events not exceeding 2-sec duration)**	105 dB

* Represents airblast, not measurable with an ordinary sound level meter.

** Represents noise, measured with the "C" scale of a conventional sound level meter, which is sensitive to approximately the same range of frequencies as the human ear.

TABLE 2.

CONDITIONS REQUIRING ADDITIONAL CAUTION BECAUSE OF ANOMALOUSLY HIGH LEVELS (HL) AIRBLAST OR FREQUENCIES (HF) THAT ARE IN THE RANGE (5 TO 25 Hz) OF STRUCTURAL RESPONSE.

Large charge weight delay	HL
Effective delay too short (reinforcement)	HL
Effective delay too long (>25 msec)	HF
Face toward receiver	HL, HF
Insufficient confinement	HL, HF
Wind toward receiver	HL
Severe temperature inversions	HL

- Use maximum possible stemming and coarse angular stemming material.
- Cover detonating cord with at least 3 inches of material.
- Avoid blasting when wind is in a critical direction.

They indicate that the proper use of delays is part of a good airblast control program. Other literature tends to minimize the importance of delays in controlling airblast.

Weather and Airblast/Noise

Weather conditions can have a significant effect on the airblast/noise impacts from a blasting operation. The primary effects are:

- Increased impacts downwind and reduced impacts upwind.
- A zone of increased airblast/noise level some distance from the source when there is a temperature inversion.

The effect of wind on airblast/noise is related to the vertical gradient in wind velocity. The presence of higher velocity winds aloft has the effect of refracting the sound waves back toward the surface. This increases the downwind noise levels.

A severe temperature inversion (Figs. 10 and 11) may cause a zone of little noise near the blasting site and a zone of loud noise farther away. As an example, the most damage from an accidental detonation of 112,000 pounds of explosive in Texas occurred 7 to 10 miles from the point of the blast. An inversion layer at 5,000 feet altitude caused the refraction (American Insurance Association 1972). Since temperature inversions occur most frequently at night and in the early morning, blasting at this time may accent off-site noise levels. Additional information on weather and blasting is presented in a publication by Cox et al. (1954).

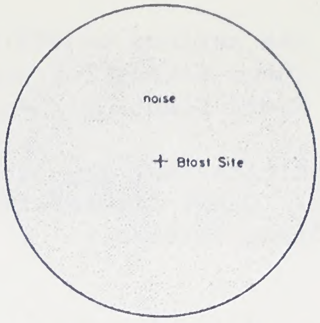
IMPACTS AND MITIGATION MEASURES

Structural Impacts

Structural damage may occur from ground vibration or from airblast. As most Western coal mines are away from population centers, complaints regarding structural damage are rare. Where mines are near housing developments (as near Gillette, Wyoming), the mining companies are normally careful about blasting and comply with the State regulations (see earlier section on "Vibration") as required in their permits to mine. At least one company with a mine near a housing development has purchased a house near the mine boundary and installed seismic monitoring equipment in it. As indicated earlier, mining companies must keep records of all blasts and make those records available to the public upon request.

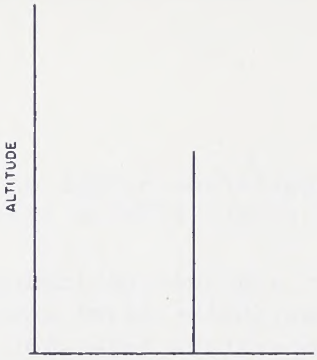
Figure 10.

WEATHER AND AIRBLAST

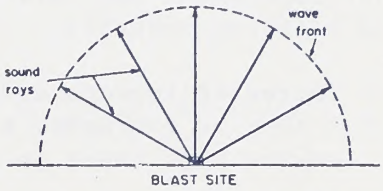


Horizontal plane showing sound return - noise decreases with distance from blast site

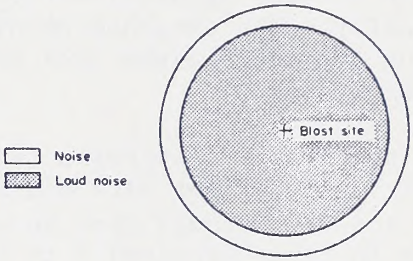
–Sound propagation from an isothermal condition (sound speed constant with altitude).



Constant sound speed & temperature with altitude

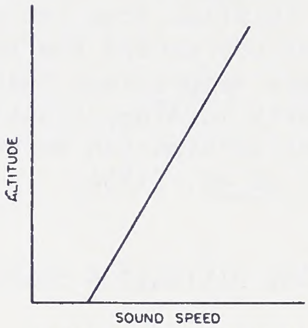


Vertical plane showing sound propagation

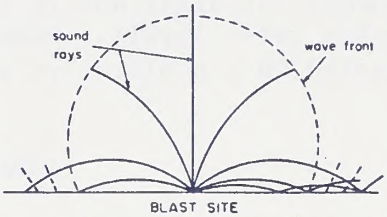


Horizontal plane showing sound return zones of loud noise adjacent to relatively little noise

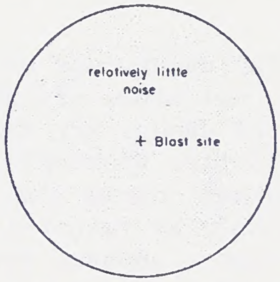
-Sound propagation from a positive thermal gradient (sound speed increases with altitude).



Increasing sound speed & temperature with altitude

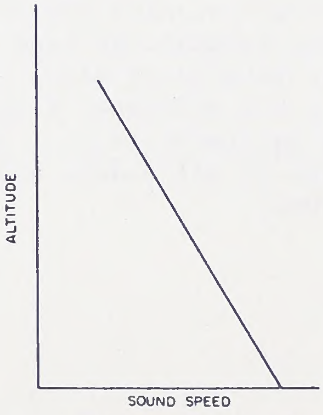


Vertical plane showing sound propagation and refraction

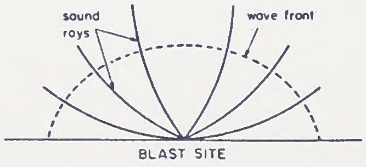


Horizontal plane showing sound return - relatively little noise at site rapidly fading with distance

–Sound propagation from a negative thermal gradient (sound speed decreases with altitude).



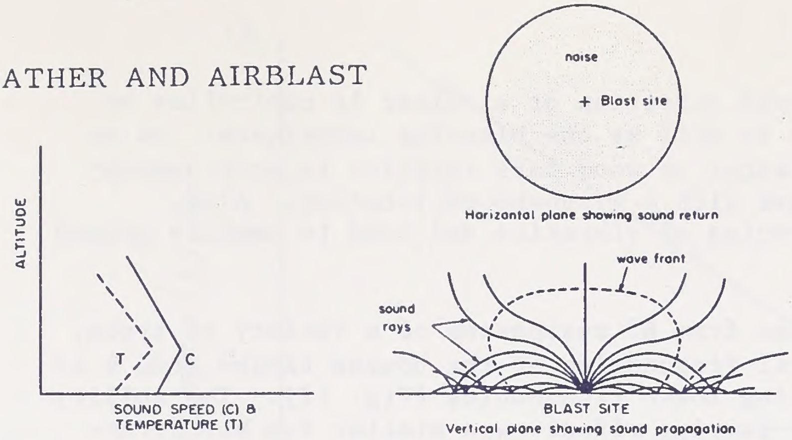
Decreasing sound speed & temperature with altitude



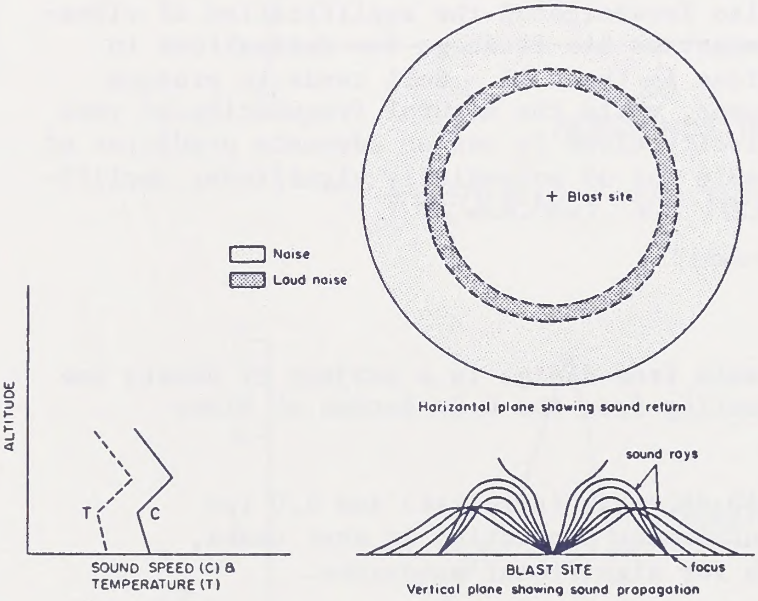
Vertical plane showing sound propogation

Figure 11.

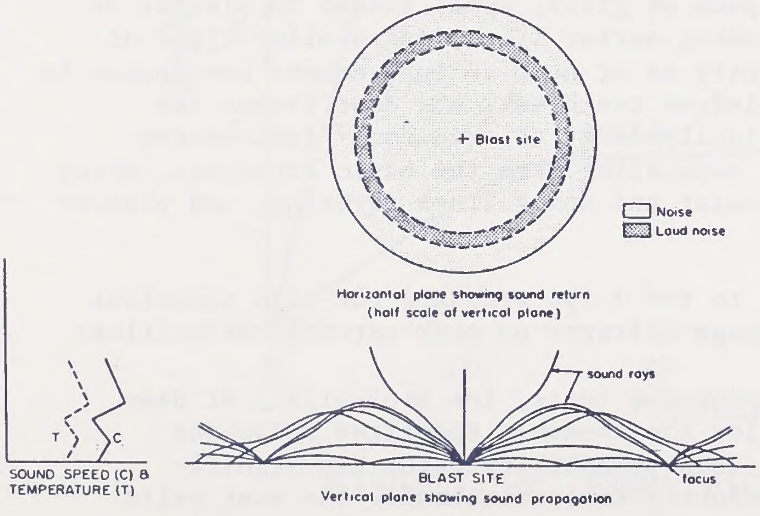
WEATHER AND AIRBLAST


noise
+ Blast site
Horizontal plane showing sound return
ALTITUDE
T
C
SOUND SPEED (C) & TEMPERATURE (T)
wave front
sound rays
BLAST SITE
Vertical plane showing sound propagation

–Sound velocity increases for a short distance upward and then decreases with further height. In this condition, no zones of silence will be present and the sound will be characterized by a rumble of relatively long duration. The duration of the sound is caused by the sound rays reaching the listener at different times via multi direct and reflected paths.


+ Blast site
Noise
Loud noise
Horizontal plane showing sound return
ALTITUDE
T
C
SOUND SPEED (C) & TEMPERATURE (T)
sound rays
BLAST SITE
focus
Vertical plane showing sound propagation

–Sound velocity decreases in the lower altitude, then increases for a similar distance and finally decreases again. In this case, a zone of relatively little noise exists near the blasting location, with loud noise disturbance at more distant locations. A narrow zone in which the sound return is especially loud and sharp occurs outside the relatively quiet zone. This is a result of a bundle of rays returning to the ground at these points at nearly the same time forming a focus or "caustic". Beyond this zone of very loud noise, other sound rays are returning to the ground, but are lower in intensity and sharpness.


+ Blast site
Noise
Loud noise
Horizontal plane showing sound return (half scale of vertical plane)
T
C
SOUND SPEED (C) & TEMPERATURE (T)
sound rays
BLAST SITE
focus
Vertical plane showing sound propagation

–A third common sound-speed inversion that may exist is one in which, with altitude, the velocity successively increases, decreases, increases once more a greater rate, and finally decreases. In this case, there is a zone of noise surrounding the blasting site and proceeding in all directions. The noise in the zone nearest the blast site will be a rumble of relatively long duration. This atmospheric condition also results in a zone of very loud noise due to focusing of rays.

Structural Design Factors

The potential for damage from ground vibration or airblast is controlled by the type and age of the structure as well as the blasting techniques. As an example, an older house with a plaster on wood lath interior is more susceptable to damage than a modern house with a gypsumboard interior. Also, buildings have fundamental frequencies of vibration and tend to amplify ground vibrations in varying degrees.

Medearis (1979) presents data taken from 63 residences of a variety of types, heights, and ages. The fundamental frequencies of the houses ranged from 4 to 18 Hz, with the taller houses having lower frequencies (Fig. 12). The ability of the houses to cease vibrating--damping effect--was similar for all structures. The median damping value was 5.2 percent (expressed in terms of reduction in vibration from one cycle to the next).

Because blasting can produce ground vibrations and airblast in the frequencies that houses respond to, Medearis also investigated the amplification of vibrations by structures. Figure 13 summarizes his findings for detonations in rock with associated ground vibrations in the soil. Soil tends to produce frequencies similar to those of houses, while the natural frequencies of rock tend to be higher. Peak ground velocity alone is not an adequate predictor of residential damage due to the variable but of potentially significant amplification of vibration by structures.

Threshold For Damage

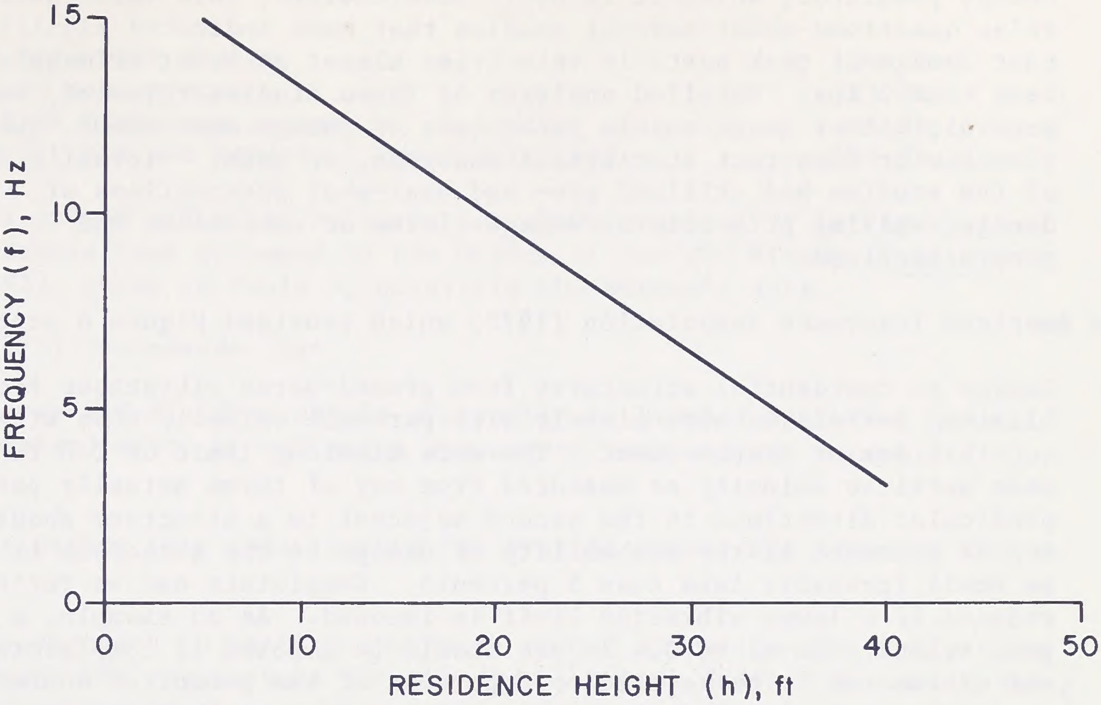
The point at which structures are safe from damage is a subject of debate due to the many variables involved. Quoting from the U.S. Bureau of Mines (Siskind et al. 1980a):

> Previously safe maximums of 140 dBL-peak (airblast) and 2.0 ips (ground vibration) provided sufficient protection in most cases, although they were high enough for significant annoyance.

Ash (1972) was more liberal in his interpretation of structural damage. With the peak particle velocity at 2 ips, damage to structure would generally be limited to: an occasional broken pane of glass, small cracks in plaster or wallborad, separation of the bond along mortar lines, and similar types of damage. With a peak particle velocity at or near 10 ips, cracks can appear in concrete foundations and floors, windows can break, and door frames can loosen. When the peak particle velocity is at or exceeds 17 ips, severe structural damage can occur--walls separating from the basic structure, brick veneers loosening and collapsing, water and sewer lines severing, and plaster or wallboard separating.

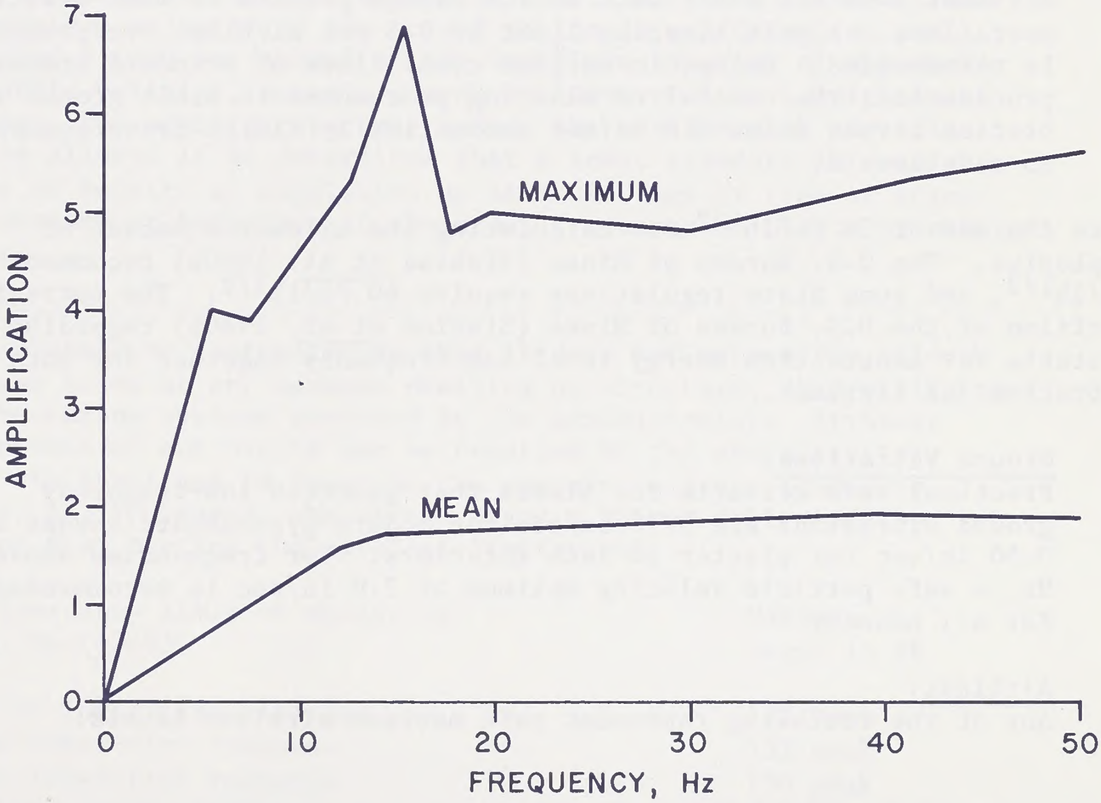
Medearis (1979) lends some support to the 2 ips standard but also questions the concept of basing threshold damage criteria on peak particle velocities:

> For the range of applicability of the tests, the probability of damage at particle velocities below the commonly specified 2 ips was found to be about 2 percent. This probability value has significance only if peak particle velocity is statistically the most valid



FREQUENCY VS. HEIGHT, ALL HOUSES

Figure 12.



STRUCTURE AMPLIFICATION, 5 % DAMPING

Figure 13.

> damage predictor, which it is not. Nevertheless, this value does raise questions about several studies that have indicated significant damage at peak particle velocities almost an order of magnitude less than 2 ips. Detailed analyses of these studies revealed, in general, either questionable techniques of damage assessment, questionable or incorrect statistical analyses, or both. Virtually none of the studies had utilized pre- and post-shot observations of damage, relying primarily on damage claims or complaints and generalizations.

The American Insurance Association (1972) which provided Figure 6 states:

> Damage to residential structures from ground-borne vibrations from blasting correlates more closely with particle velocity than with acceleration or displacement. The safe blasting limit of 2.0 in/sec peak particle velocity as measured from any of three mutually perpendicular directions in the ground adjacent to a structure should not be exceeded if the probability of damage to the structure is to be small (probably less than 5 percent). Complaints can be further reduced if a lower vibration limit is imposed. As an example, a peak velocity level of 0.4 in/sec should be imposed if complaints and claims are to be kept below 8 percent of the potential number of complaints and claims are to be kept below 8 percent of the potential number of complaints. In the absence of instrumentation, a scaled distance of 50 ft/lb$^{1/2}$ may be used as a safe blasting limit for vibrations.
>
> Airblast does not contribute to the damage problem in most blasting operations. A safe blasting limit of 0.5 psi airblast overpressure is recommended. Except in extreme cases (lack of standard stemming procedures), the control of blasting procedures to limit ground vibration levels below 2.0 in/sec automatically limits overpressures to safe levels.

Note the use of 50 ft/lb$^{1/2}$ for calculating the allowable amount of explosive. The U.S. Bureau of Mines (Siskind et al. 1980b) recommends 70 ft/lb$^{1/2}$, and some State regulations require 60 ft/lb$^{1/2}$. The current position of the U.S. Bureau of Mines (Siskind et al. 1980b) regarding safe criteria for blasts ties energy level and frequency together for both ground vibration and airblast.

> Ground Vibrations:
> Practical safe criteria for blasts that generate low-frequency ground vibrations are 0.75 in/sec for modern gypsumboard houses and 0.50 in/sec for plaster on lath interiors. For frequencies above 40 Hz, a safe particle velocity maximum of 2.0 in/sec is recommended for all houses.
>
> Airblast:
> Any of the following represent safe maximum airblast levels:

0.1-Hz high-pass system	134 dB
2-Hz high-pass system	133 dB
5- or 6-Hz high-pass system	129 dB
C-slow (events not exceeding 2-sec duration)	105 dB

The Bureau's ground vibration criteria are shown graphically in Figure 14. One of the regulations proposed by the Office of Surface Mining (Federal Register 1982), shown in Table 3, parallels the Bureau's data.

Medearis (1979) recommends that:

> The charge and distance should preferably be limited such that the one standard error of estimated structural response not exceed 1.5 in/sec.

Curves illustrating this relationship for typical houses are shown in Figure 15.

The simplest approach to setting limits to ground vibration and airblast may be to reference the regulations the mine is operating under. Because Wyoming has the largest number of operating coal surface mines in the Rocky Mountain/ Great Plains area, its regulations are listed below. A mine must follow these regulations to maintain its permit to mine.

> Ground Vibrations:
> In all blasting operations, except as otherwise stated, the maximum peak particle velocity of the ground motion in any direction shall not exceed 1 inch per second at the immediate location of any dwelling, public building, school, church or commercial or institutional building. The administrator may reduce the maximum peak particle velocity allowed if he determines that a lower standard is required because of density of population or land use, age or type of structure, geology or hydrology of the area, frequency of blasts or other factors.
>
> Airblast:
> Airblast shall be controlled so that it does not exceed the values specified below at any manmade dwelling or structure, when utilizing those measuring systems approved by the administrator. Airblast measurements of any blasts may be required by the administrator, unless the structure is owned by the operator and not leased to another, or, if leased, the lessee signs a waiver relieving the operator from meeting the airblast limitations.

Lower frequency limit of measuring system, Hz (±3dB)	Maximum level in dB
0.1 Hz or lower-flat response	135 peak
2 Hz or lower-flat response	132 peak
6 Hz or lower-flat response	130 peak
C-weighted, slow response	109 C.

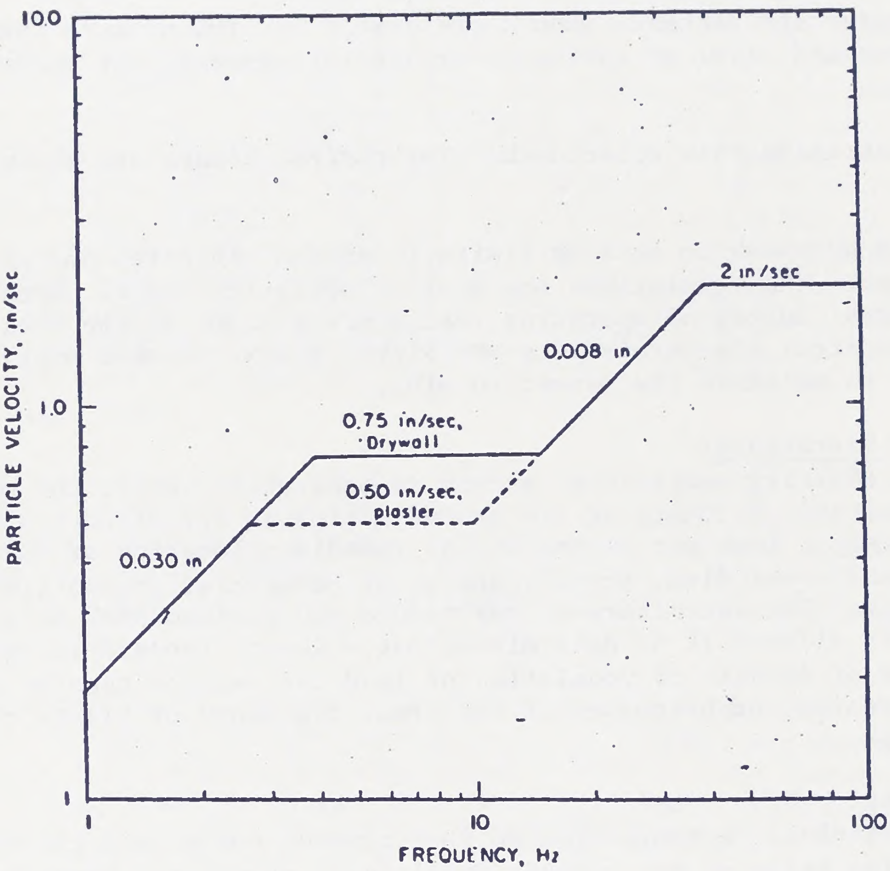


Figure 14.

BLASTING LEVEL CRITERIA

TABLE 3.

ONE OF THREE OPTIONS FOR MAXIMUM GROUND VIBRATIONS PROPOSED IN THE FEDERAL REGISTER OF MARCH 24, 1982.

Type of Structure[a]	Maximum peak particle velocity in inch/second allowable with seismic monitoring at indicated hertz value		
	<10 Hz	10 to 40 Hz	>40 Hz
1	0.50	0.50	0.50
2	0.75	1.0	2.0
3	1.0	1.5	2.0
4	2.0	2.0	2.0
5[b]	---	---	---

[a] 1. Sensitive or protected structures such as historic buildings, monuments, and residences with construction elements such as plaster interiors and rough stone foundation walls.

2. Older homes more than 20 years old with construction elements such as plaster-on-lath interiors and deteriorated or rigid, easily fractured construction materials.

3. Modern homes less than 20 years old with gysum-board interior, reinforced concrete or concrete-masonry-unit foundations, and other wood-frame and wood-clad structure.

4. Structures with safety considerations such as water towers, impoundments, tunnels, pipelines, towers, and underground mines.

5. Buildings or structures designed to resist dynamic loads such as earthquake, wind, traffic, etc.

[b] Maximum; peak-particle-velocity to be determined by a qualified registered professional engineer.

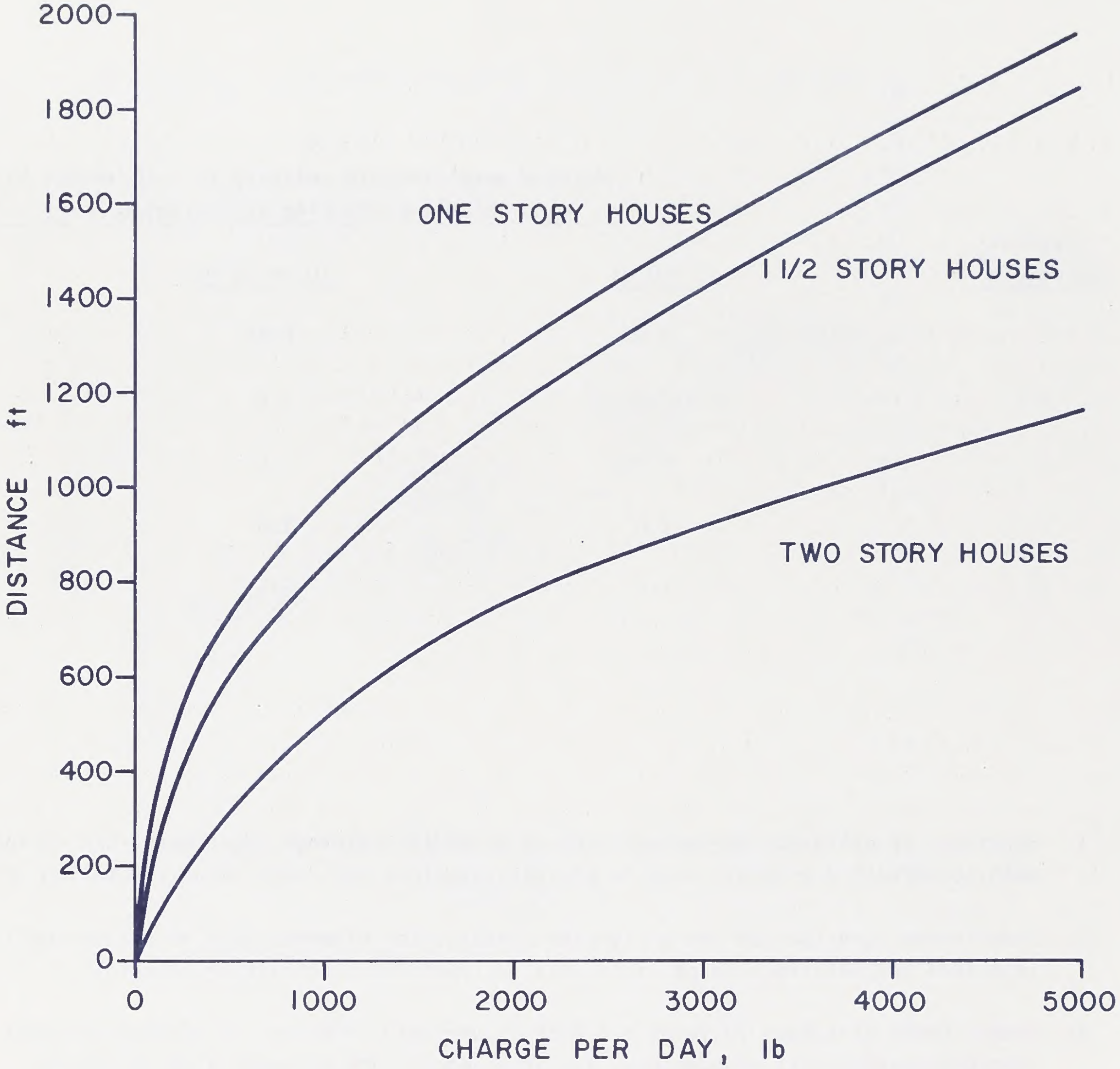


Figure 15.

DISTANCE VS. CHARGE, 1.5 IN. PER SEC RESPONSE

In all but the last C-weighted case, the measuring systems used shall have a flat frequency response of at least 200 Hz at the upper end. The C-weighted shall be measured with a Type 1 sound level meter that meets the standard ANSI S1.4-1971 specifications.

The State regulations governing blasting at surface coal mines parallel those developed by the Office of Surface Mining. The Federal Register (March 13, 1979) provides additional information regarding the rationale behind the Federal regulations.

Common Types of Damage

While Ash (1972) outlined types of structural damage up to and including the failure of walls, almost any blast-related damage beyond minor cracking of plaster may indicate that the associated mine is utilizing illegal blasting procedures. Current regulations, as listed above, are designed to minimize off-site blasting damage.

The ground vibration from blasting stresses a building in three dimensions. These stresses may produce crisscross cracks in the walls at about 45° to the ground. As plaster is usually the weakest material in a building, the effects of the vibrations usually appear in plastered walls and ceilings. Damage will first appear as extensions of old cracks and then in the formation of new cracks at about right angles to each other.

Window breakage is the first indicator of excessive airblast levels. Poorly set glass may break at an overpressure of 1.0 pound-per-square inch. This is several times the highest levels (0.01 to 0.02 lb/in^2) normally associated with structures near modern surface mines.

The American Insurance Association (1972) elaborates on how to differentiate between blasting- and nonblasting-related minor structural damage. A topic not discussed in the AIA publication is who is responsible for damage resulting from a combination of substandard construction and high, but legally acceptable, levels of ground vibration. Allegations of major structural damage from blasting may require an intensive on-site investigation, since the substantiation of such claims could imply the use of illegal blasting techniques by the nearby mine.

Preblast Surveys

Damage surveys conducted after the alleged damage has occurred are of questionable value, especially where the blasting is supposed to have accelerated existing damage. Preblasting surveys of nearby structures are often part of a good operational procedure utilized by mining companies. Also, most State regulations allow the owner of structures near a coal surface mine to request a preblasting survey at the expense of the mine owner.

A third party, approved by the State regulatory agency, may conduct the survey on behalf of the operator to determine the condition of the structure and document any preblasting damage and other physical factors that could reasonably be affected by the blasting. Assessing structures such as pipes, cables, transmission lines, and wells and other water systems would be limited to surface condition and other readily available data. Special attention would be given to the preblasting condition of wells and other water systems used for human, animal, or agricultural purposes and to the quantity and quality of the water.

A written report of the survey would be prepared and signed by the person who conducted the survey. The report would include any special conditions or proposed adjustments to the blasting procedures that should be incorporated into the blasting plan to prevent damage. Copies of the report would be provided to the person requesting the survey and to the administrator. The person requesting the survey could submit any written disagreements he has with the results of the survey to the mine owner and the regulatory agency. Information on preblast surveys is provided by Chironis (1979). An example of a preblasting survey conducted by AMAX is attached as Addendum A.

Mitigation Measures

The measures to mitigate structural damage from ground vibration and airblast are described in the sections on "Vibration" and "Airblast." The primary techniques are:

Ground Vibration: Limiting the amount of explosive detonated in any delay period.

Airblast: Providing proper stemming. Eliminate surface detonating card.

Groundwater Impacts

The impacts of blasting on groundwater have been widely discussed but seldom documented. The groundwater drawdown associated with the mine pit will normally have a greater impact on groundwater resources than blasting.

Geohydrology

Data on the geology and hydrology of any active coal mine will be available in the mine's State permit application. This information will include a description of the aquifers intercepted by the mine, premining water level and water quality measurements, a description of the probable impacts of the mine on the groundwater, and usually a set of maps showing the probable groundwater drawdown resulting from the mine.

The groundwater will occur in the more permeable zones, possibly including the coal. The relatively tight shales often found at Western coal mines restrict the vertical movement of groundwater, often causing confined aquifers and/or perched aquifers to occur (Fig. 16). References on groundwater which may be helpful include:

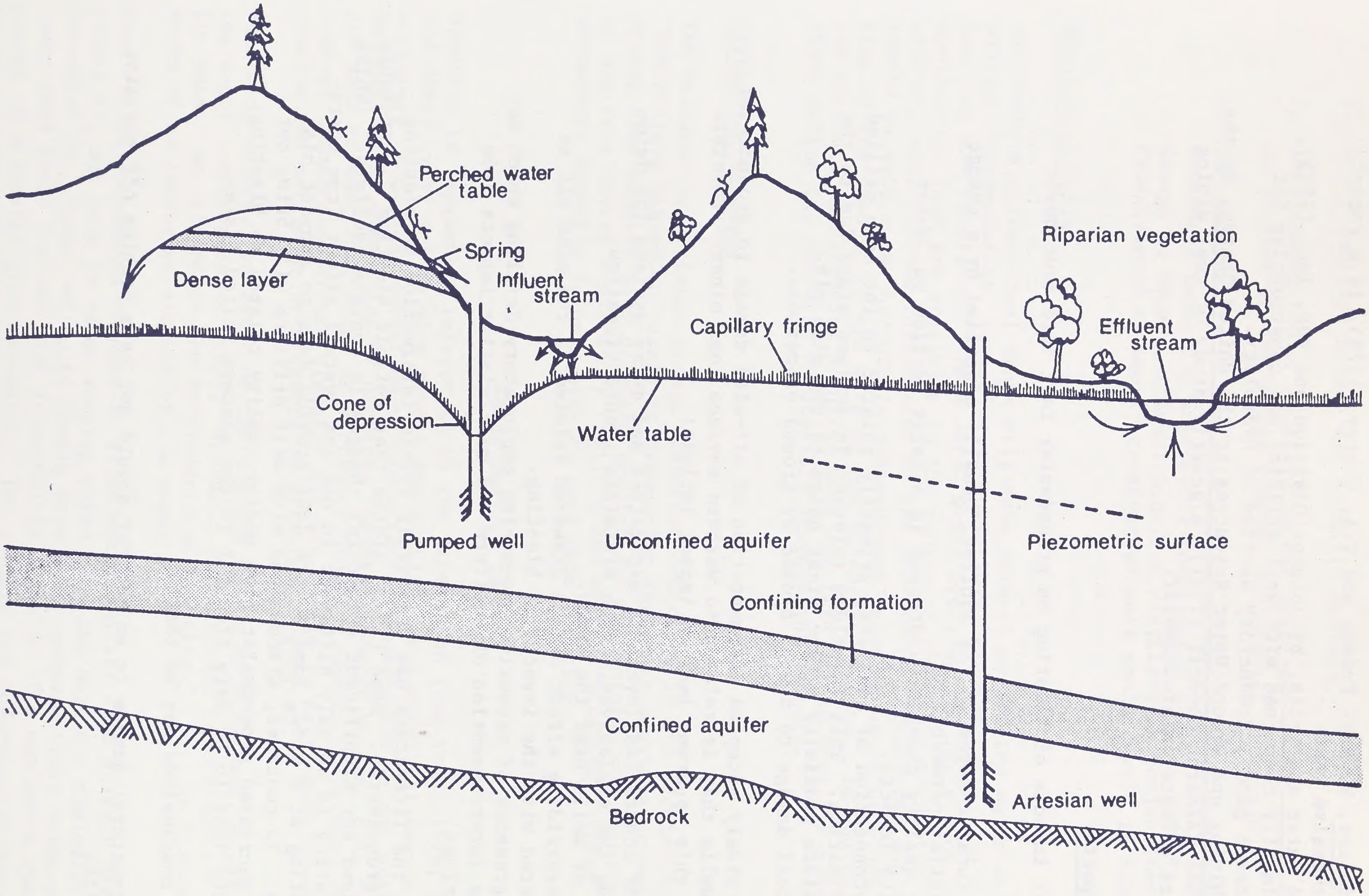


Figure 16.

GROUND WATER

- Groundwater, by R.A. Freeze and T.A. Cherry (1979), is a recent, comprehensive text.
- Ground Water and Wells, by Johnson Division and VOP, Inc. (1975), is primarily concerned with well drilling and construction but includes a good introductory section on hydrology.
- Coal Mining and Ground Water Resources in the United States, by the National Research Council (1981), a generic study of coal mining and its effects on groundwater.

Potential Impacts

The potential impacts of blasting on groundwater fall into four basic categories:

- Structural changes in the aquifer, usually signified by a change in aquifer permeability.
- Water quality changes, addressed in a later section on "Water Quality Impacts."
- Interconnection of aquifers, primarily related to the hole drilled for blasting. This is seldom relevant in surface mines due to the immediate proximity of the blast holes to the mine pit.
- Physical damage to a well caused by ground vibrations.

There is no widely accepted documentation of off-site damage to groundwater systems or wells that is related to Western surface coal mines. Possible reasons for this apparent lack of impact include:

- Use of controlled levels of explosives and delay systems for detonating the explosives, which minimizes ground vibration.
- Lack of wells near the mines.
- The overriding effect of the drawdown related to the mine pit as compared with the impacts of blasting.
- The presence of extensive pre-mining exploratory drilling which may cause interconnection of aquifers and mask similar impacts from blasting.

In general, the literature has relatively little information on blasting impacts on groundwater. Bond (1975) states that seismic blasting "...probably has not caused any significant structural changes in Montana aquifers." While seismic blasting is notably different in use and overall effect from operational blasting at a mine, Bond's work does provide data to support his conclusions. In contrast, discussions with well drillers will bring out reports of decreased groundwater flow and/or quality related to blasting. These reports tend to be more frequent in the eastern United States.

Reasonable conclusions may be that:

1. Structural damage to an aquifer should not be a problem off the mine site.

2. Water quality changes are normally minimal.

3. Interconnection of aquifers is not critical, as the blasting occurs in an area of overburden removal and mineral extraction.

4. The possibility of properly conducted surface coal mine blasting adversely impacting a properly constructed well is remote. As with damage to houses, illegal blasting practices in conjunction with a deteriorated or poorly constructed well could result in damage.

Monitoring Wells

All Western surface coal mines will have several monitoring wells with above-average documentation, including geologic logs, electric logs, and diagrams of how they are completed. These data, which are required for a mine permit application (and are available to the public at the State regulatory agency's office), will include information on the pre-mining groundwater quality and levels as well as a "hydrologic consequences" section which provides a prediction of the impacts of the mine on the hydrologic system. In conjunction with the periodic measurements required over the life of the mine, it provides the first option for checking on possible groundwater impacts.

Mitigation Measures

The measures to minimize ground vibration described in the section on "Controlling Vibration" apply to preventing damage to aquifers or wells. Some States have adopted hole plugging regulations to minimize the interconnection of aquifers during exploratory drilling and seismic blasting. These procedures normally do not apply to coal mine blasting.

Water Quality Impacts

Blasting is frequently referenced in the literature (Van Voast 1974; Dettmann and Olsen 1978) and in mine permit applications as a potential source of nitrates. But, substantial cause and effect documentation is not available. Because, large quantities of nitrates (perhaps several hundred tons per year) are used at most coal mines as a primary blasting agent, it is easy to make a logical connection between elevated nitrate levels in surface or groundwater samples and spills or by-products of blasting materials.

According to W.A. Van Voast of the Montana Bureau of Mines and Geology (personal correspondence 1982), "Sporadic high nitrate concentrations do occur (in water) as related to the by-products of blasting." But, he indicates he knows of no intensive studies of the question.

Bond (1975) documented changes in groundwater quality from seismic blasts (Table 4), but only in water samples taken from the hole the explosive was detonated in. Dissolved solid levels from other seismic blast holes were lower than those for the hole presented in Table 4. The explosive was 25 pounds of a seismic grade dynamite. The primary but undocumented water quality impact may be due to accidental spills and/or undetonated holes.

TABLE 4.

QUALITY OF WATER FROM KELTNER SEISMIC HOLE

All values are milligrams per liter unless otherwise specified.

Time:	*	**	--	17:00	11:00	18:00
Date:	12-17-70	12-17-70	12-21-70	5-17-71	6-27-72	6-27-72
Spec. conductance	1300	4650	1100	840	887	839
Std. deviation	.86	.85	-1.32	-.86	-1.65	0.20
pH	7.74	8.91	8.05	7.84	7.57	7.45
SAR***	2.3	41.5	0.9	0.7	0.8	0.7
Calcium (Ca)	53	17	62	75	78	72
Magnesium (Mg)	38	57	46	54	59	58
Sodium (Na)	92	1590	40	33	39.2	32.8
Potassium (K)	6.3	29.5	4.7	4.3	4.8	4.1
Iron (Fe)	.03	.18	.00	12.41	0.1	0.00
Manganese (Mn)	0.20	0.03	0.08	0.83	0.00	0.00
Bicarbonate (HCO_3)	258	2937	221	241	238	230
Carbonate (CO_3)	0	33	0	0	0	0
Sulfate (SO_4)	230	865	185	267	269	262
Chloride (Cl)	25	27	31	19.6	18.1	17.3
Nitrate (NO_3)	2.2	6.3	4.1	9.6	5.6	10.6
Fluoride (F)	0.3	0.7	0.2	0.17	0.3	0.3
Silica (SiO_2)	3.7	13	3.3	6.4	--	--
Carb. hardness	211	278	181	198	195	189
Noncarb. hardness	80	0	162	214	243	229
Alkalinity	211	2000	181	198	195	189
Calc. TDS	709	4805	598	724	712	687

* Before shot
** After shot
*** Sodium adsorption ratio

Typical Water Quality Data

The ground and surface water at Western mines tend to be naturally high in dissolved solids. But, materials and quantities present are quite variable. A set of "typical" measurements cannot be given. Table 5 (Knapton and McKinely 1977) illustrates the variability of data for a fixed station on a stream draining a portion of the coal fields in Montana.

Groundwater quality measurements taken at a single well seldom vary like the surface water quality data shown. But, it is possible to obtain significantly different measurements from different aquifers, vertically under the same point. It is critical to know what geologic unit a well is completed in and if that unit is well sealed off from other geologic units. Domestic wells (and monitoring wells) frequently provide the mechanism for interconnecting dissimilar aquifers.

The best source of water quality data may be the baseline data and routine monitoring data collected as required by the mine's permit. These data are available to the public at the office of the State regulatory agency.

By-products of Blasting

The by-products of blasting fall into two main categories--those resulting from:

* Proper detonation of the explosive, primarily gases, and those from
* Spills, sloppy housekeeping, intentional dumping, and incomplete detonation.

Chaiken et al. (1974) provided a list of the by-products of an ideal detonation of ANFO (Table 6). Theoretically, N_2 is the dominant form of nitrogen. The potentially water-soluble nitrogen oxides and ammonium are present in rather small quantities. A well-detonated explosive should release only trace amounts of undesirable materials to the adjacent overburden or coal.

In contrast to the seismic blasts referenced previously, the blasted materials are usually removed immediately by mining. They are not part of a functioning aquifer. But, a major goal of reclamation at most mines is to restore the groundwater system. As a result, blasting has a substantial indirect impact on groundwater quality. The tremendous surface area exposed by fragmenting the overburden is now available to contribute material, via leaching, which may degrade the quality of the future groundwater. Any residue from blasting which is incorporated into the spoils may also be available to leaching.

Nitrate is the most frequently mentioned contaminant. It is soluble in water and potentially present in large quantities. In spite of its obvious connection to blasting, it is difficult to verify the exact source of nitrates detected in water samples by normal laboratory techniques. The overburden may

TABLE 5.

WATER QUALITY VALUES FOR ARMELLS CREEK NEAR FORSYTH.

Property	No. Of Analyses	Mean	Range	Units
Discharge (Q)	25		0.04-462	ft^3/s
Specific conductance (at 25 deg. C)	25	3670	395-6500	umhos/cm
pH	24	8.2	7.4-8.7	units
Temperature	25	9.5	0.0-25.0	deg. C
Turbidity	25	55	1-400	JTU
Dissolved oxygen	25	98	69-138	percent
Biochemical oxygen demand	25	2.5	.0-9.9	mg/L
Calcium (Ca), dissolved	25	111	24-210	mg/L
Magnesium (Mg), dissolved	25	120	12-250	mg/L
Sodium (Na), dissolved	25	640	35-1000	mg/L
Percent sodium	25	62	36-80	percent
Sodium-adsorption ratio	25	10	1.5-18	---
Potassium (K), dissolved	25	10	6.5-12	mg/L
Bicarbonate (HCO_3)	25	523	89-913	mg/L
Carbonate (CO_3)	24	4	0-36	mg/L
Sulfate (SO_4), dissolved	25	1700	110-2700	mg/L
Chloride (Cl), dissolved	25	31	4.7-260	mg/L
Fluoride (F), dissolved	25	.4	.1-.6	mg/L
Silica (SiO_2), dissolved	25	6.2	1.2-14	mg/L
Dissolved solids (calculated)	25	2870	245-4210	mg/L
Nitrite plus nitrate, total as N	25	.06	.00-.23	mg/L
Nitrogen, ammonia, total as N	25	.05	.00-.16	mg/L
Nitrogen, total organic as N	25	.94	.31-2.0	mg/L
Nitrogen, total kjeldahl as N	25	.99	.34-2.1	mg/L
Phosphorus, total as P	25	.10	.01-.51	mg/L
Suspended sediment	24	159	13-1100	mg/L

TABLE 5. (continued)

WATER QUALITY VALUES FOR ARMELLS CREEK NEAR FORSYTH

	(Dissolved)		(Total)		
Property	No. Of Analyses	Value Or Range	No. Of Analyses	Value Or Range	Units
Aluminum	2	10	6	210-2200	ug/L
Arsenic	2	1-2	11	0-5	ug/L
Beryllium	2	0-<10	11	0-20	ug/L
Boron	25	140-600	---	---	ug/L
Cadmium	2	0	11	<10-20	ug/L
Chromium	2	<10-10	11	0-64	ug/L
Copper	2	1-3	11	<10-300	ug/L
Iron	25	0-510	11	250-9700	ug/L
Lead	2	0-3	11	<100-100	ug/L
Lithium	2	30-40	11	10-60	ug/L
Manganese	2	60-120	11	30-210	ug/L
Mercury	2	.0-<.1	11	.0-.6	ug/L
Molybdenum	2	2-<6	11	0-5	ug/L
Nickel	2	3-6	11	<50-100	ug/L
Selenium	1	0	11	0-1	ug/L
Vanadium	2	2.3-<8	---	---	ug/L
Zinc	2	<10-20	6	10-40	ug/L

TABLE 6.

IDEAL DETONATION PROPERTIES OF ANFO CONTAINING 6% FUEL OIL,

	Detonation Product Composition, Moles/kg³
H_2O	27.4
N_2	11.7
O_2	0.002
H_2	0.253
NO	0.053
NO_2	5×10^{-5}
N_2O	3×10^{-4}
NH_3	0.050
O	2×10^{-4}
OH	0.006
H	0
CO_2	3.53
CO	0.761
HCN	0.002
CH_4	2×10^{-5}
C	0
Total Gas	43.7
C (solid)	0

be high in natural nitrate (5 to 50 ppm) before additional nitrate is introduced by blasting.

Due to the relatively innocuous nature and low cost of many blasting agents (as opposed to detonating devices), there is limited incentive to handle them carefully. The contamination of overburden or water by accidental or intentional spills of blasting materials is difficult to document. These spills are seldom reported to the mine permitting agency as the people responsible may consider it simply dumping a little fertilizer on the ground. The primary component of ANFO is identical to the ammonium nitrate fertilizer used by many farmers.

Spills of ANFO or other blasting agents which occur in the mine may eventually be detected as elevated nitrate levels in the discharge from the mine's settling ponds. These ponds receive surface runoff from disturbed areas and water pumped from the mine pit. As the groundwater gradient is normally toward the mine pit, most groundwater contaminated by blasting should flow into the mine pit sump. Some mines will contract with an off-site plant for the delivery of the blasting agent directly to the drill holes and will not store ANFO or similar compounds on site. This may minimize on-site spills.

Mitigation Measures

The primary mitigation measure is the establishment of good housekeeping practices. Personnel associated with blasting believe that there is limited potential for the contamination of ground or surface water by properly set and detonated explosives. But, contamination does appear to occur. The exact relationship between nitrate contamination and poor blasting/housekeeping techniques is unclear due to a lack of data.

Air Quality Impacts

Blasting emits substantial quantities of gases to the atmosphere. The following calculation provides an indication of the amount:

Mine production: 5 million tons of coal per year
1. Five million tons of coal equals approximately 5 million yd^3,
2. Assume an equivalent amount of overburden to be blasted,
3. Use an average powder factor of 0.4 lb/yd^3,

$$(10 \text{ million } yd^3)(0.4 \text{ lb/yd}) = 4 \text{ million lb of explosive.}$$

Applying conservation of mass principles, the above amount of material must be emitted or somehow disposed of. As indicated by Table 6 most of it becomes water or nitrogen gas. Dust or particulate emissions resulting from blasting must also be considered.

Typical Atmospheric Emissions

Table 7 provides the primary emissions from various explosives. By utilizing the above estimate that a 5 million-ton-per-year mine might use 4 million pounds (2,000 tons) of ANFO per year (ignoring the PETN, etc., in the detonating devices), the emissions can be calculated:

(2,000 tons) (67 lb/ton CO) = 134,000 lb/yr CO
(2,000 tons) (17 lb/ton NO_x) = 34,000 lb/yr NO_x
(2,000 tons) (2 lb/ton SO_2) = 4,000 lb/yr SO_2

While these numbers seem large, the quantities are emitted over a year and diffuse readily into the atmosphere. In comparison, a 750-megawatt power plant with a scrubber emits approximately:

SO_2 = 6,000 lb/hr
NO_x = 5,000 lb/hr
CO_2 = 1,600,000 lb/hr

Total suspended particulate (TSP) levels are affected by blasting activities. Data have been collected by Morrison-Knudsen Company on three active mines in the Western United States (BLM Air Quality Handbook for Surface Coal Mines 1982) and normalized to a 1 million-ton/year production level. These data have been combined with EPA emission factors to predict the approximate TSP levels resulting from blasting at typical Western coal mines (Table 8).

Mitigation Measures

There are no significant mitigation measures for controlling gaseous atmospheric emissions. The gaseous emissions are so low that they are not included in permit-related air quality inventories.

The particulate emissions are high enough to be included as part of the overall mine-related particulate emissions. There are no generally accepted particulate control techniques beyond moderating the direct contribution of blasting by proper blast hole stemming and reducing the indirect contribution from trucks by watering the access roads. Mine permits typically require that the area to be blasted be minimized and that overshooting be prevented as the standard techniques for controlling particulates. Blast hole drill rigs are routinely equipped with dust control devices, frequently a water spray system.

Flyrock

Roth (1979) indicates that flyrock is the source of most blasting-related injuries and property damage in surface mining. This should not be a significant cause of off-site damage with Western surface coal mines due to their isolation from developed areas.

TABLE 7.

POUNDS OF EMISSIONS PER TON OF EXPLOSIVE.

Explosive	CO	NO_x	Other
Dynamite, Standard	281		6, H_2S
Dynamite, Ammonium	63		31, H_2S
Dynamite, Gel	104	53	4, H_2S; 1, SO_2
ANFO 5.8 - 8% FO	67	17	2, SO_2
TNT	796		29 NH_3, 27 Cyanide, 121 C_2H_2, 1.1 C_2H_6
RDX	196		44 NH_3
PETN	297		2.5 NH_3

Note:

NO_x is a generalized symbol for the various oxidized forms of nitrogen.

TABLE 8.

PARTICULATE EMISSIONS FROM IDEALIZED ONE-MILLION-TON·PER-YEAR MINES.

Type of Mine/Operation	Operations/Year (for 1 million tons)	EPA Emission Factor	Pounds Particulate Per Year for 1 Million Tons Coal
Dragline:			
Drilling overburden blast holes	3,800	1.5 lb/hole	5,700
Drilling coal blast holes	2,600	0.22 lb/hole	572
Blasting overburden	200*	85.3 lb/blast	17,060
Blasting coal	200*	78.1 lb/blast	15,620
			38,952
Truck/Shovel:			
Drilling overburden blast holes	6,000	1.5 lb/hole	9,000
Drilling coal blast holes	2,700	0.22 lb/hole	594
Blasting overburden	200*	85.3 lb/blast	17,060
Blasting coal	200*	78.1 lb/blast	15,620
			42,274
Scraper/Shovel:			
Drilling overburden blast holes	4,300	1.5 lb/hole	6,450
Drilling coal blast holes	2,700	0.22 lb/hole	594
Blasting overburden	200*	85.3 lb/blast	17,060
Blasting coal	200*	78.1 lb/blast	15,620
			39,724

*Limited sensitivity to coal production levels.

State regulations normally provide that flyrock shall not go farther than one-half the distance to the nearest occupied structure and that it shall not leave the mine property. Since violations of these regulations are fairly obvious, serious problems seldom occur. The primary means of controlling flyrock is proper stemming. If necessary, additional control can be obtained by modifying the drilling pattern and the amount of explosive per hole.

Annoyance Factors

Human response to ground vibrations, noise, and airblast are considerably below the levels necessary to cause damage to structures. The American Insurance Association (1972) indicates that personal discomfort is a major factor causing people to file complaints.

The U.S. Bureau of Mines (Siskind _et al_. 1980b) also recognizes human reactions to ground vibration as a limiting factor to blasting:

> Human reaction to vibration is dependent on event duration as well as level. Particle velocities of 0.5 in/sec from typical blasting (1-sec vibration) should be tolerable to about 95 pct of the people perceiving it as distinctly perceptible." Relevant to whole-body vibration reaction is the degree that the vibration interferes with activity (sleep, speech, TV viewing, reading), presents a health hazard, and affects task proficiency. For people at home, the most serious blast vibration problems are house rattling, fright (fear of damage or injury), being startled, and, for a few, activity interference. Complaints from these causes can be as high as 30 pct at 0.5 in/sec, and this is where good public relations attitudes and an educational program by the blaster are essential.

The U.S. Bureau of Mines (Siskind _et al_. 1980a) also recognizes airblast as an annoyance factor:

> Levels exceeding 120 dB will produce some annoyance from rattling and fright, with as much as 5 to 10 pct of homes exhibiting such disturbances at the maximum level of 134 dBL (0.1-Hz high-pass). Public reaction depends strongly on the blaster's public relations and the general attitudes of the neighbors to the economic and social requirement for the blasting. Tolerance increases where jobs are involved.

Figures 17 and 6 (from the earlier discussion of ground vibration and airblast/noise) provide guidelines for human response.

Control measures take two forms:

- Increased public relations effort to encourage the residents to tolerate moderate disturbances.

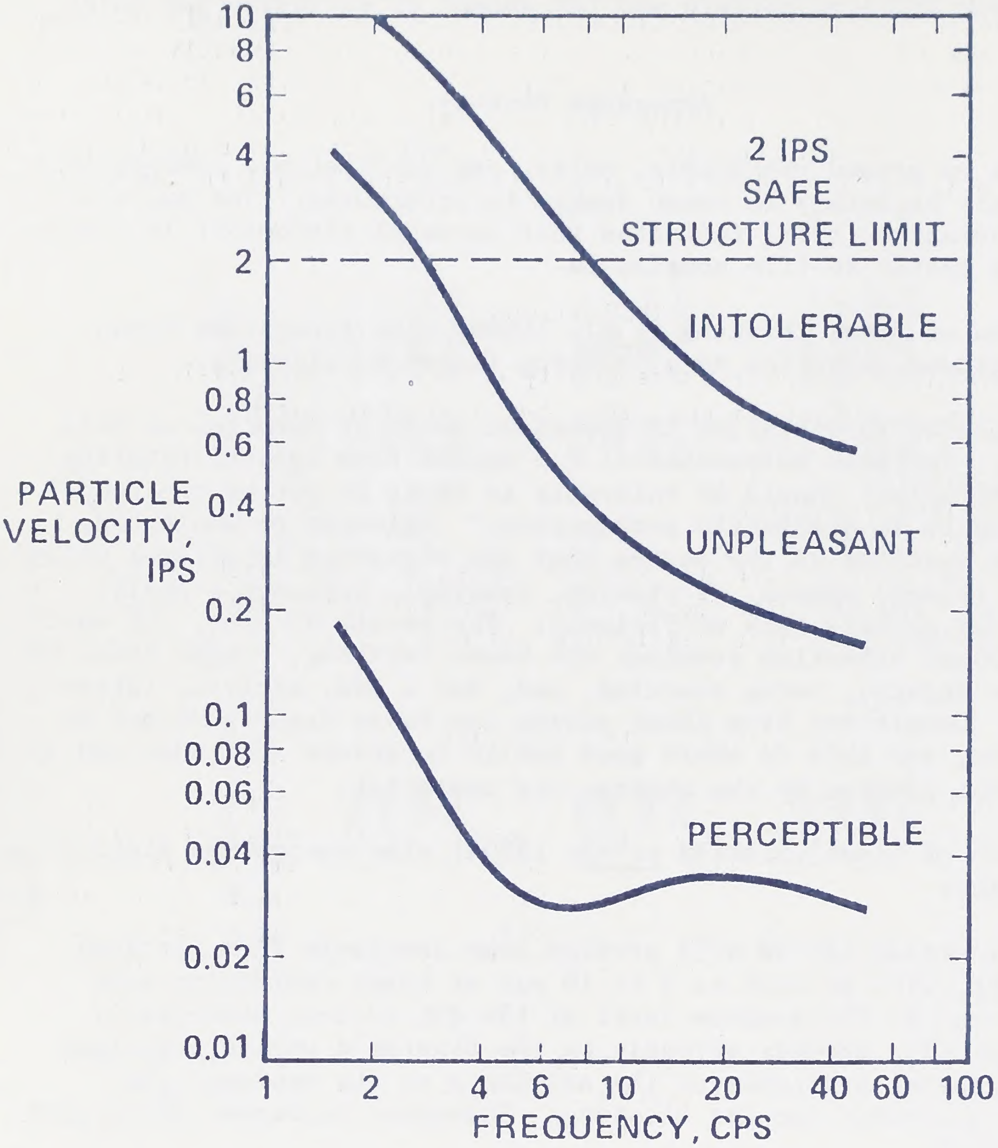


Figure 17.

RESPONSE OF HUMANS TO VIBRATIONS

* Modified blasting procedures, utilizing the techniques listed earlier, to reduce ground vibration and airblast/noise levels below those which just meet regulatory requirements.

Some annoyance problems may be controlled by eliminating blasting at unexpected times and/or time periods (dinner, late evening, early morning) when blasting may be more disturbing. State regulations normally prohibit blasting between sunset and sunrise and require that blasting schedules be given to nearby residents. Avoiding blasting under atmospheric temperature inversions that may "focus" the sound on areas away from the mine (Fig. 11) can reduce complaints, especially from people not accustomed to the routine blasting noise.

REGULATIONS

Regulations governing explosives frequently occur at those levels--local, State, and Federal. They also fall into two basic categories:

* Safety-related.
* Off-site impact-related.

The safety-related regulations are referenced in most handbooks (e.g., Du Pont 1978) and texts. The off-site impact-related regulations are normally obtained from the State mining regulatory agency.

Manufacture, Sale and Use

Primary responsiblity for control of the sale and use of explosives is assigned to the U.S. Treasury Department, Bureau of Alcohol, Tobacco and Firearms (ATF). It has published regulations governing and controlling the manufacture, transportation, storage (distance from permanent installations, combustible material, and type of enclosure), and licensing sales of explosives and blasting agents. A document (ATF 1977) containing the regulations can be obtained from ATF.

The Mine Saftey and Health Administration (MSHA) is also a Federal agency which, among its other roles, enforces compliance with ATF regulations. MSHA also requires a mining company to submit a proposed blasting plan, approves or disapproves the plan, and regulates compliance.

State agencies do not apply a uniform code of regulations to the use of explosives. Many states allow MSHA to be the governing agency enforcing ATF regulations. In other cases, states have regulations more rigid and stringent than ATF or MSHA. In addition to the required ATF license, most states require a State license to purchase and use explosive or blasting agents. This license is normally issued to an individual or individuals working directly with or in control of blasting at a mining operation.

Local governing bodies occasionally pass and enforce very stringent regulations governing the use, transport, and storage of explosives. These regulations vary substantially with geographic location and address problems encountered locally with use, transport, and storage of explosives.

Federal Surface Mining Program

The Surface Mining Control and Reclamation Act of 1977 (SMCRA) sets forth the permit requirements and environmental performance standards governing the use of explosives in surface coal mining. The reguations are found in 30 CFR Parts 780, 816, and 817. The Federal Register (March 13, 1979, and March 24, 1982) is an excellent reference on the potential impacts of blasting and the regulatory controls related to them. The final Federal regulations on blasting will be published in the Federal Register in early 1983.

The Office of Surface Mining (OSM) in Denver (303/837-2451) may be able to provide additional assistance regarding the above regulations.

State Coal Mining Programs

The Western States have coal mining regulations which parallel the Federal Surface Mining Control and Reclamation Act of 1977. These regulations normally contain both permit requirements and performance standards.

The permit requirements may be helpful, since they require the collection of baseline data on geology, hydrology, meteorology, etc.--data that are meteorology important to understanding the physical characteristics of the site. In addition, the permit application will contain the names and addresses of all landowners within a half mile of the site and a mine plan. The mine plan will include topographic maps showing the pit advance and a narrative and supporting illustrations regarding blasting procedures. These documents are available for public inspection at the office of the State regulatory agency:

Colorado Mined Land Reclamation Board
Denver, Colorado
303/839-3567

Department of State Lands
Helena, Montana
406/449-2074

Public Services Commission
Bismark, North Dakota
701/244-4096

Department of Environmental Quality
Cheyenne, Wyoming
303/777-7756

An additional seven copies of each State mine permit application are filed with the Office of Surface Mining in Denver (303/837-2451) if the area to be mined includes Federal coal leases or Federal surface ownership. One of these copies is then forwarded to the Bureau of Land Management, usually to the District Office which has control over the proposed mine site.

The performance standards included in the State regulations are the most practical limitations on blasting impacts. They incorporate an existing mechansim for enforcing conformance with the procedures/limitations specified. This comment also applies to any special blasting or mitigation procedures that are described in the mine's State program permit. Once the mining permit application is formally submitted by the mine and approved by the State, it becomes part of an agreement between the two parties, which allows the State to enforce any special procedures described in the permit.

Typical State surface mining-related performance standards for blasting will include requirements for:

* Compliance with all local, State, and Federal laws.
* Signs marking the blasting area.
* Preblasting surveys conducted at the request of nearby landowners.
* Providing blasting schedules to the public.
* Controlling access to areas to be blasted.
* Limiting airblast/noise.
* Limiting ground vibration.
* Restricting blasting near certain types of facilities, including domestic dwellings.
* Keeping records on all blasts.

Other State regulations that may be applicable are those related to air quality and wastewater discharges. An air quality evaluation and permit are required for surface mines. Relative to blasting, suspended particulate matter, but not the gaseous emissions, will be reviewed. The water treatment facilities, which normally include one or more settling ponds which receive water pumped from the mine pit, require a discharge permit. This water from the mine pit is the obvious place to check for elevated nitrate levels. The agencies to contact for additional information are:

Department of Health
Denver, Colorado
303/320-4180 (air)
303/320-8333 (water)

Department of Health and Environmental Sciences
Helena, Montana
404/449-3454 (air)
404/449-2406 (water)

Department of Health
Bismark, North Dakota
701/224-2348 (air)
710/224-2354 (water)

Department of Environmental Quality
Cheyenne, Wyoming
307/777-7391 (air)
307/777-7781 (water)

Due to the nearly inseparable relationship between State and Federal air and water quality regulations, the U.S. Environmental Protection Agency's Region VIII Office in Denver (303/837-3895) may be of assistance.

SUMMARY

Due to improved blasting techiques; regulations limiting allowable ground vibration, airblast, and flyrock; and the relative remoteness of most mines; off-site impacts from blasting at Western surface coal mines should be minimal. The existing literature is not in agreement as to the level of off-site impact that is allowable. In the case of groundwater and water quality, it does not clearly document the level of impact that may occur.

Ground vibration should be controlled to keep off-site particle velocities below 2.0 in./sec and possibly as low as 0.5 in./sec. Airblast should be kept under approximately 130 dB (low frequencies) and noise under approximately 105 dBc. But these ground vibration and noise levels may not be adequate to prevent complaints due to human response, as opposed to structural damage impacts.

The primary impact-mitigation techniques utilize millisecond delays between the detonation of charges in a multiple-charge blast pattern and stemming (backfilling) the blasting drill holes above the explosive. Minimizing the use of excessive amounts of explosive may also be important. These techniques are widely accepted as they are compatible with increasing blasting effectiveness and/or reducing blasting costs.

A secondary impact mitigation technique, but one that may be critical relative to water quality, is good housekeeping. While not documented, it appears that surface or groundwater contamination may be due to poor blasting procedures and/or spills of materials.

The best sources of information for someone working on surface mining blasting complaints are the mine's State program mining permit and the related blasting records.

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ADDENDUM A

PREBLASTING SURVEY FORMAT
UTILIZED BY AMAX*

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*This material has been taken directly from an AMAX report. Personal data has been removed.

AMAX COAL COMPANY
A DIVISION OF AMAX INC.

STRUCTURAL SURVEY

DATE: March 5, 1981 MINE: Eagle Butte ID# 4801078

TIME: 4:00 A.M. P.M. X

REQUESTED BY: VIA: PHONE: x MAIL:

NAME:

ADDRESS: Longs Lane TELEPHONE:

Rawhide Village Gillette, Wyoming ZIP CODE: 82716

DATE & TIME SURVEY COMPLETED: March 24, 1981 3:30 P.M.

DESCRIPTION & LOCATION OF PROPERTY: one family dwelling with garage attached

Longs Lane Rawhide Village Gillette, Wyoming

CONDITION OF ALL STRUCTURES INCLUDING PIPES, CABLES, TRANSMISSION LINES, WELL AND OTHER WATER SYSTEMS (DESCRIBE FULLY): one family dwelling with basement, paneled and attached garage; 4 bedrooms and 2 full baths; has outside chimney, built by owner, of cinder block and is partially covered with Native Stone but not completed; The garage has an extension being built on but is not complete; backyard is fenced-in with chain link fence; exterior and interior walls and ceiling are in very good condition; all cables and pipe are underground

See attached photos for defects

AMAX COAL COMPANY

STRUCTURAL SURVEY WORKSHEET

TYPE OF CONSTRUCTION: Frame AGE: 5 years

TYPE OF ROOF: Composition Shingle AGE: 5 years

	OK	COMMENTS
EXTERIOR WALLS	X	Masonite siding
INTERIOR WALLS	X	Sheet rock
DOORS	X	Wood
WINDOWS	X	Wood and aluminum storm windows
CHIMNEYS	X	outside Cinder block partly veneer Native Stone
FIREPLACES	X	Wood Stove in basement
FLOORING	X	Wood
BATH FIXTURES	X	Fiberglass upstairs Steel- downstairs
CERAMIC TILE		
FURNACE	X	All electric baseboard
WATER HEATER	X	40 gallon electric
AIR CONDITIONER	no	
SIDEWALKS	X	concrete (see photos)
DRIVEWAYS	X	concrete (see photos)
MASONRY	no	
DECORATIVE STONE	No	
DOWNSPOUTS	X	gutters and down spouts, except new addition
OUT BUILDINGS	no	
WATER SUPPLY	X	Rawhide System
SEWER OR SEPTIC	X	Sewer
PLUMBING	X	coppertubing and plastic discharge pipe
CABLES	X	underground
TRANSMISSION LINES	X	underground

DESCRIPTION OF QUALITY & QUANTITY OF WATER IN WATER SYSTEM (ATTACH WATER QUALITY & QUANTITY ANALYSES WHERE APPROPRIATE):

Water is supplied by the Rawhide water system. Also the sewage.

RECOMMENDATIONS OF ANY SPECIAL CONDITIONS OR PROPOSED ADJUSTMENT TO BLASTING PROCEDURES WHICH SHOULD BE INCORPORATED IN BLASTING PLAN TO PREVENT DAMAGE:

AMAX will comply with Wyoming DEQ-LQD regulations, Chapter VI, Section 5,b. with regard to the weight of explosives used to prevent damage.

COMPLETED BY: R. Clyde Dallas

ASSIGNED BY:

SURVEY SUMMARY INFORMATION

NAME OF HUSBAND

NAME OF WIFE

NAMES & AGES OF CHILDREN

HUSBAND'S OCCUPATION Electronic Technician-

WIFE'S OCCUPATION Homemaker

YEARS OF RESIDENCY 5 years

HOUSE DIMENSIONS 24' x 62'

ANY SPECIAL MEDICAL OR PHYSICAL CONDITIONS OF TENANTS none

ANY SPECIAL CONDITIONS OF STRUCTURES

ANY NOTES ADJUSTOR FEELS IMPORTANT

MR. AND MRS.
LONGS LANE RAWHIDE VILLAGE
GILLETTE, WYOMING

The dwelling is occupied by Mr. and Mrs. and their three children ages 20, 18 and 15.

Mr. is a electronic technician with the Company. Moving to Gillette from Texas 5 years ago, the home was new at that time.

An extension is being built onto the garage at this time. The outside chimney was built by the owner and is partially veneered with Native Stone. MR. is also doing this work. (veneer)

The home faces the north with the chimney on the east end. The backyard is fenced with chain link fence.

All walls, exterior and interior (also ceilings), are in very good condition with very few minor defects.

Mrs. says she is very happy to be living in this location. What few defects in the photos are normal and there is no complaints about our mining at this time.

DESCRIPTION OF PROPERTY

One story frame Masonite siding

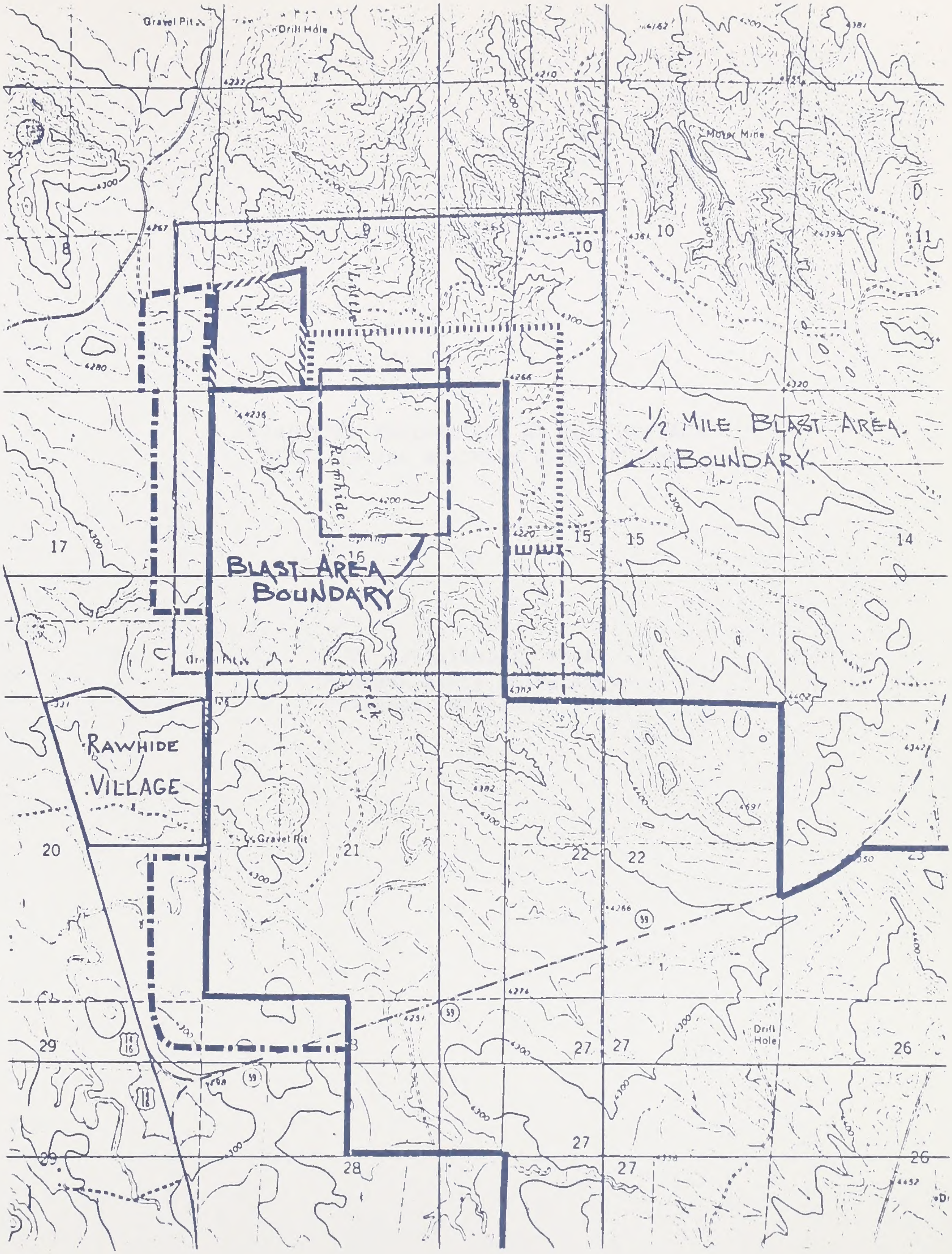
Composition shingle roof

Basement and attached garage

The house faces the north on a paved street

The house was built about 5 years ago.

See photos attached


Gravel Pit
Drill Hole
Mohr Mine
8
10
10
11
½ MILE BLAST AREA BOUNDARY
Little
Rawhide
Creek
Spring
16
17
15
15
14
BLAST AREA BOUNDARY
RAWHIDE VILLAGE
Gravel Pit
20
21
22
22
23
29
28
27
27
27
27
26
26
Drill Hole
59
16

OVERBURDEN RECLAMATION AT COAL SURFACE MINES IN THE NORTHERN GREAT PLAINS

by

D. J. Dollhopf, Ph.D.
Montana State University
Bozeman, Montana 59715

INTRODUCTION

Increased coal demand from Westeren States has created concern that coal mining operations may adversely affect the long-term quality of the land resource. Concern stems from the possibility that overburden and coal seam aquifers will take on, to a certain extent, the chemical characteristics of their new flow medium composed of spoils. Overburden and interburden zones considered unsuitable for reclamation purposes due to chemical or physical characteristics are encountered in this region. Therefore, it is important that unsuitable overburden be isolated from the hydrological system, and similarly, such material should not be deposited within the plant root zone where it may adversely affect revegetation.

Reclamation of overburden is a relatively new science. The following discussion presents the state-of-the-art regarding evaluation and management of coal overburden in the Northern Great Plains. This information should be useful to professionals responsible for either mine permit development or applications evaluation.

COAL OVERBURDEN GENESIS

Coal overburden in the Northern Great Plains was deposited by mainly three processes: glacial, fluvial, and marine systems (Fig. 1). Overburden deposited by glaciation is located in the northern half of North Dakota, while overburden deposited by river systems (fluvial) dominates mine sites in southern North Dakota, Montana, Wyoming, and the North Park Coal Field in north-central Colorado. Marine systems dominate coal fields in northwestern Colorado within the Green River Region (Fig. 1). These depositional systems partially explain the existence of geochemical zones unsuitable for reclamation.

Glacial Depositional System

Present-day coal mine sites north of the Missouri River have overburden that was largely deposited by glaciation. As glaciers accumulated over this region they eroded soil and rock material and transported this debris great distances. Unlike water and wind transport, there is almost no sorting of sediment during glacial transport. As the climate warms and a glacier retreats, three layers of material are deposited. As a result of erosion at the immediate bottom of the glacier, a basal layer is deposited atop undisturbed bedrock. As the glacier melts and retreats, debris held within the ice is dropped atop the basal deposit; this is termed an ablation deposit. Water from glacial melt then transports a sediment load over the ablation deposit. Since a glacier may advance and retreat many times over the same area, these deposits may be sequentially stacked over each other or eroded and mixed again (Fig. 2).

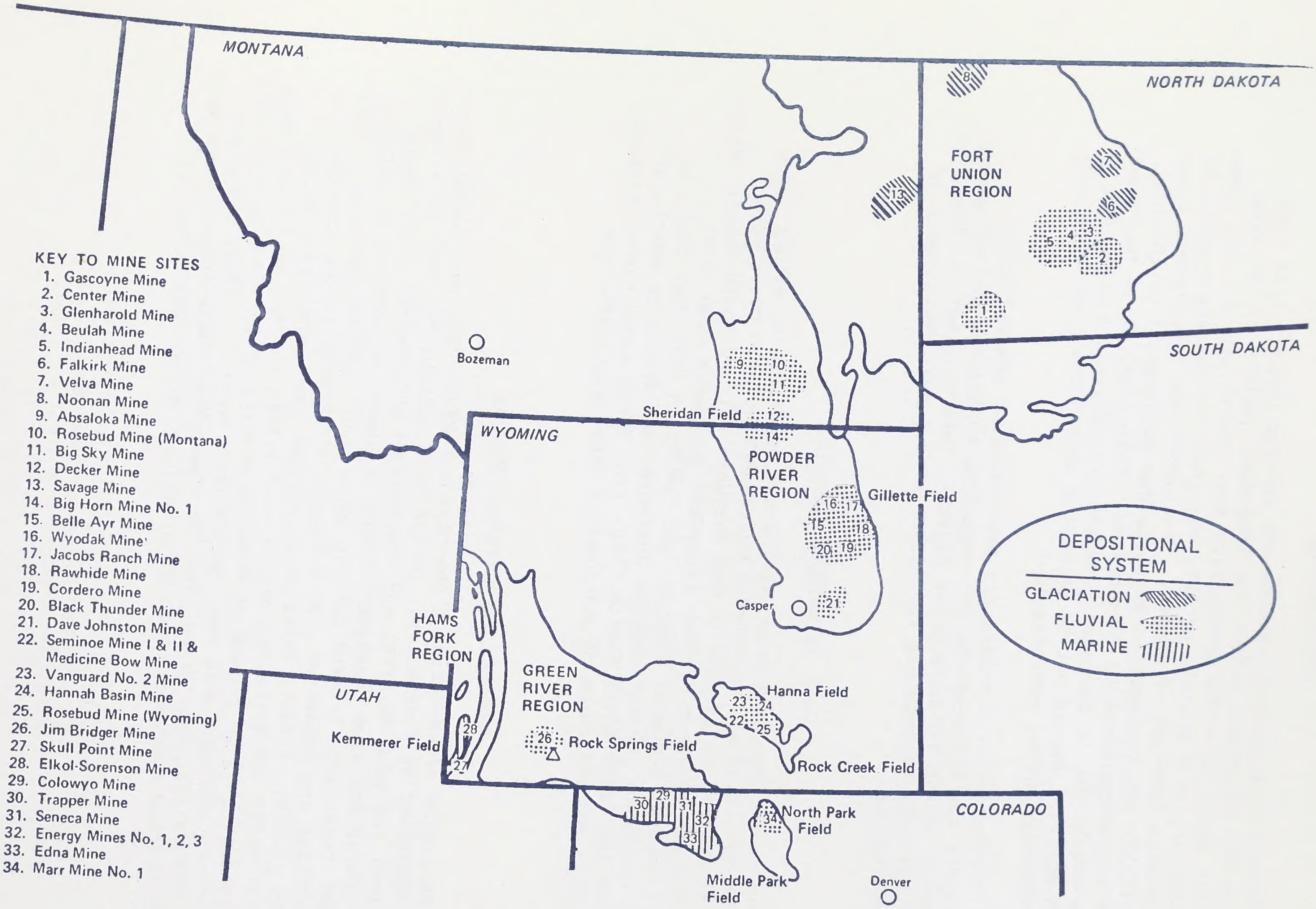


Figure 1. Overburden depositional system of some surface coal mines in the Northern Great Plains.

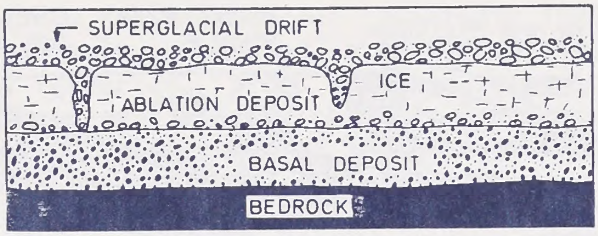


Figure 2. Schematic representation of glacial deposition (from Reineck and Singh 1975)

Overburden deposited in this manner can have a highly variable geochemistry, since materials were transported from a wide geographical area, mixed, and finally were deposited largely unsorted. In general, overburden in this region tends to be coarse textured with much boulder-gravelly material present. Few physiochemical problems are present in these materials.

Fluvial Depositional System

Overburden deposited by fluvial systems in the Northern Great Plains includes those mine sites south of the Missouri River in North Dakota, the Colstrip area of Montana, Sheridan Coal Field, Gillette Coal Field, Hanna Coal Field, Rock Springs Coal Field in Wyoming, and the North Park Coal Field in Colorado (Fig. 1). The source of these fluvial overburden deposits was the Rocky Mountain to the west. The igneous, metamorphic, and sedimentary complexes of the Rocky Mountains were eroded by rivers that carried sediments eastward to depositional basins.

Fluvial deposits can be grouped into three types: channel, bank, and flood basin, deposits (Fig. 3). Channel deposits generally include all depositional units created by the active stream channel. Deposition on point bars is the major process of sedimentation in meandering river channels. In addition to point bar deposits, channel lag, channel fill, and point bar swale deposits are included in this regime. Channel lag deposits consist of residual pebbles and gravels that accumulate in deeper portions of the channel. These deposits exist as lenticular bodies that are invariably discontinuous. Point bars are depositional features formed on the inside of river meanders and vary in size with the size of the river or stream that created them. Sediments in point bars, along with the channel lag, consist of the most coarse sediment available to the stream. Some point bar deposits in the research area vary between medium and very fine sand, generally in a fining upward sequence which may be repeated. Associated with point bars are point bar swales, depressions formed between successive point bars. The swales fill with fine-grained sediments, forming small lenticular deposits.

Bank deposits are formed during flooding when overbank flows create natural levees and crevasse splay deposits. These sediments are generally fine sand and silts, with coarser materials deposited nearest the channel and texture becoming finer at greater distances from the channel. Much of the sandy-silty material in the study area appears to have been deposited by this mechanism.

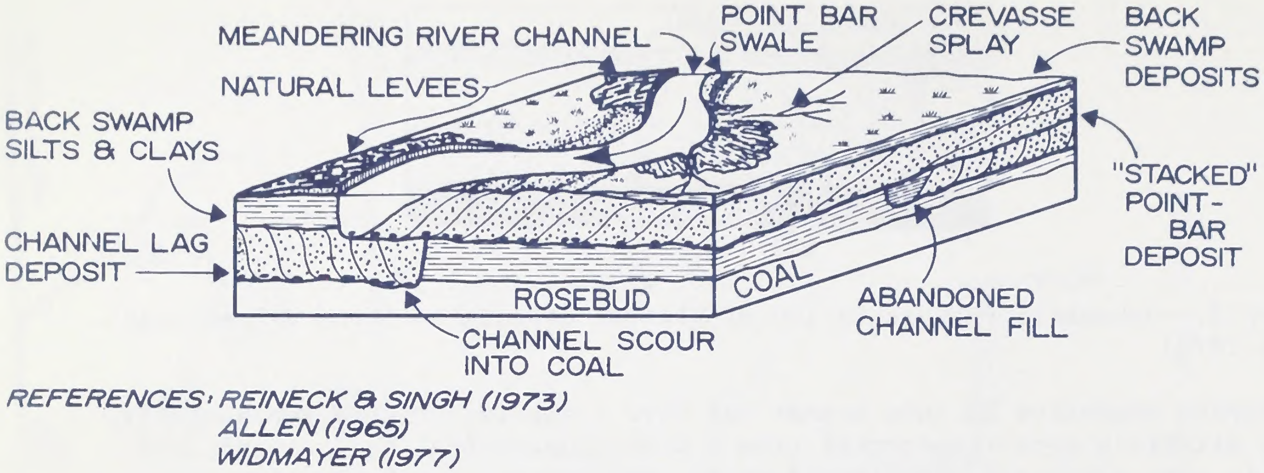


Figure 3. Schematic of a fluvial depositional system for coal overburden in the Northern Great Plains (from Dollhopf et al. 1981).

Flood basin deposits consist of the fine-grained silts and clays deposited when heavy flooding inundates the flood basin and its back swamps. Typical sediments are thin clay and silt stratification, marsh, and coal deposits.

The fluvial depositional system creates overburden where geochemical patterns can change extensively over a few hundred feet. The meandering nature of a stream will stack-up and/or recut channel, bank, and flood basin deposits over geologic time. Some evidence suggests the fine-textured flood basin deposits most frequently contain physiochemical characteristics unsuitable for reclamation. Approximately half of the mine sites with a fluvial depositional system are plagued with sodic and/or clayey overburden materials which complicate reclamation. In addition, trace metals are often found in excess of state suspect levels.

Marine Depositional System

Surface coal mines in the northwestern corner of Colorado within the Green River Region have overburden deposited largely by a marine environment. These mine sites are located within the Mesa Verde Formation containing Cretaceous coal seams with a Lewis Shale overburden. The Kemmerer Coal Field in extreme southwestern Wyoming is also dominated by a marine depositional system.

These areas were once large saline seas and sediments were deposited by different modes, including lake, deltaic, lagoon, and bay environments. Since water was the transport medium, sediments experienced some separation of fine from coarse materials. Mine sites in this region often contain saline and/or clayey overburden materials which may limit reclamation.

Overburden Geochemical Characterization

The Surface Mining Control and Reclamation Act repeatedly indicates unsuitable (toxic) overburden materials must be handled so as not to limit reclamation of the plant, soil, and water resources. Since the depositional systems in the Northern Great Plains produced overburden with great geochemical variation over short distances, accurate delineation of inhibitory overburden zones at a mine site is a technological problem. The optimum overburden sampling intensity is discussed later; however, some general principles are presented here.

Rarely is a geochemical problem confined to a single lithology (rock type) unit in a project area. For example, more often we see a sodic problem present in all rock types in the area. Often there is a trend where the shales may be sodic most frequently; but the exceptions to the trend are so numerous that one cannot implement a geochemical overburden handling plan based on lithology traits.

Rarely is overburden color an accurate indicator of geochemical toxicity. Again, trends are often present; for example, bright colors (reds, orange) may indicate an oxidized condition and favorable chemical levels, but exceptions to the trend are usually so numerous that an actual plan to specially handle a geochemical problem cannot be implemented.

The complexity of the depositional systems in the Northern Great Plains is the main reason for our inability to correlate either lithology or color to geochemical problems. Intensive overburden sampling and laboratory analysis are the only means to accurately characterize overburden.

Overburden Management

It is highly unlikely that all the overburden in a coal project area would be toxic or unsuitable for reclamation. This is because the depositional system, either glacial, fluvial, or marine, results in overburden with great geochemical variation. Therefore, a lithology unit that tends to have toxic chemistry would not extend far. A project area will generally have numerous zones of unsuitable material in between suitable materials for reclamation. It follows then that a mine permit application will probably never be refused for the reason that no suitable root zone material is available in the project area.

Conversely, almost all mine sites will have some overburden that is unsuitable for reclamation. The options are either selective handling and burial, spoil mixing-dilution, or special revegetation management to account for a poor growth substrate. These topics are discussed in the following sections.

OVERBURDEN HANDLING CONSIDERATIONS

In the past, both the mine design and overburden handling method were selected purely on the basis of economic considerations. Today, reclamation regulations affect both the machinery selection and whether advance or retreat mining methods are implemented. These topics are discussed below.

Blasting and Swell Factors

In the Northern Great Plains the overburden is usually blasted into an unconsolidated state prior to the spoiling process. This is accomplished by drilling 10-inch diameter holes through the overburden on a 30-foot grid system. These drill holes are cased with a plastic bag and filled with ANFO, an explosive composed of a diesel fuel and NH_4NO_3 mixture. After blasting the overburden has swelled only slightly, perhaps 1 to 3 percent.

As materials are placed in the backfill area, the porosity increases significantly, resulting in swell factors of 15 to 35 percent across mine sites in Western States. There appears to be no best method to predict swell factor in a project area. The volume of each rock type in the project area is documented, and swell factors of each rock type are estimated, resulting in a crude calculation of swell factor. Out inability to accurately determine swell factors is a complicating factor in reestablishing aquifer systems, especially alluvial valley floors.

The stripping ratio is defined as the ratio of overburden thickness to coal thickness. If the stripping ratio is 4:1 and the swell factor is 25 percent, the postmining surface elevation will be nearly identical to that in the premining state. A larger swell factor will result in a higher postmining elevation, which may make surface drainage and erosion control a problem. A lower swell factor will result in a lower postmining elevation, which may cause some internal surface drainage problems. Although premining studies are intended to develop a comprehensive surface drainage reclamation plan, our inability to accurately predict overburden swell factors renders such plans only a best estimate.

Machinery

About 1970, when coal mining in the Northern Great Plains was escalating, two out of every three mines used draglines to move overburden. The remaining mines used either truck-shovel, stripping shovel, or scraper teams. With the passage of State and Federal reclamation laws in the mid-1970s, new mine operations favored truck-shovel equipment. This trend was due, in part, to a greater flexibility in special handling of overburden materials compared with either a dragline or stripping shovel. Today in the Northern Great Plains approximately half of the mines use draglines, while the remainder use truck-shovel equipment.

Draglines

Most draglines currently in use are equipped with 325-foot booms and 40- to 80-cubic-yard buckets. This allows a dumping radius of approximately 280 feet. Although draglines are expensive, they move materials more cheaply than any other method, and maintenance cost is comparably low. Their ability to special handle materials is somewhat limited, since they can only deposit materials across the pit with their 280-foot reach. Draglines can remove 150 feet of overburden in a single pass.

Truck-Shovel

A shovel usually has a 30-cubic-yard capacity bucket and is capable of removing a 50-foot layer of overburden during a single pass. Large 100- to 350-ton trucks are used to haul the overburden. Although the trucks can transport materials to different dumps, enabling separation of overburden materials, the shovel probably has less ability to selectively dig overburden materials. Transporting overburden-interburden at sites with multiple coal seams is easier with a truck-shovel operation.

Other Machinery

Bucket wheel excavators are not being used in the Northern Great Plains to move overburden. They have been tried in recent years but the equipment either broke down or materials were too physically hard to dig efficiently. This is unfortunate, since mines in Germany and the U.S.S.R. use bucket wheel excavators and conveyor belt systems very successfully to segregate suitable and unsuitable overburden materials.

Stripping shovels with 40- to 80-cubic-yard buckets are used at a few sites to move overburden. This machine has less flexibility than a dragline for separating overburden materials. Stripping shovels are often capable of digging overburden without first blasting the material. With the advent of cheap explosives (ANFO), however, draglines quickly replaced stripping shovels.

Rubber-tired scrapers are used to move some overburden in Western States. This method is excellent for separating suitable and unsuitable overburden materials. However, all the overburden transport methods described above are much more cost-efficient, so scrapers are rarely used.

Advance and Retreat Mining Methods

At most surface coal mines in Western States the loadout facility (tipple) is located in a lowland position to enable train access. Roads used to haul coal radiate out from the tipple to the pit area. Areas outward from the tipple generally have a higher land elevation and deeper overburden thickness, a greater stripping ratio.

Advance Mining

Advance mining is when the coal nearest the tipple is extracted first and the mine progresses away from the tipple into deeper overburden as the project life matures (Fig. 4). This is economically desirable since stripping ratios are small, coal haul distances are short, and profits will be maximized during the first years of a project when development money is needed.

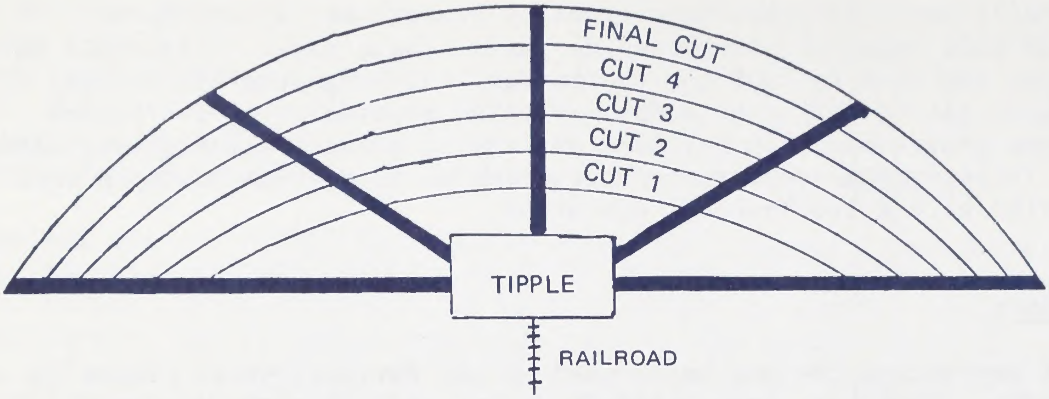


Figure 4. Aerial view of surface mine practicing an advance mining method.

Advance mining is very undesirable for reclamation. Haul roads need to be extended as the mine progresses away from the tipple. These haul roads will bisect areas that have been recontoured and prepared for reclamation for the entire life of the mine (20-30 years). Therefore, reclamation efforts will be subjected to mine activities (e.g., traffic dust) for many years, and in the end, haul road reclamation will require strips of extended bond periods within 1- to 20-year-old revegetated areas.

Retreat Mining

Retreat mining is when the coal farthest from the tipple (high stripping ratio) is extracted first and the mine progresses toward the tipple into shallower overburden as the project life matures (Fig. 5). Economically this is undesirable since stripping ratios are high, coal haul distances are long, and profits will be minimal during the first years of the project when development costs need to be recovered.

Retreat mining is desirable for reclamation, since haul roads are reclaimed as the pit progresses toward the tipple. Reclamation can thus be completed in areas where coal has been removed.

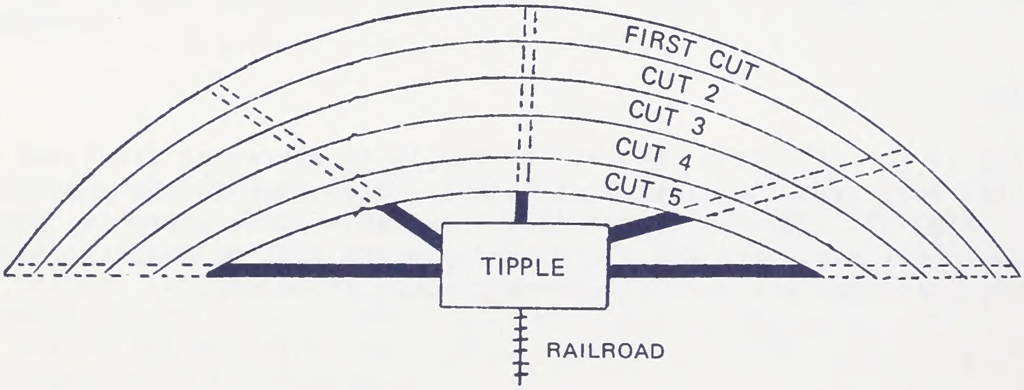


Figure 5. Aerial view of surface mine practicing a retreat mining method.

Compromise

Although advance mining is practiced at some Western coal mines, most projects implement a compromise between advance and retreat mining practices. For example, the pits may be oriented so that each cut has both thin and thick overburden in order to average out costs to move overburden during any year.

In summary, both machinery and mining methods need to be selected with considerations for reclamation. In the past, machinery and mining methods were based solely on economic considerations, and reclamation began only after the coal was out of the ground.

STATE AND FEDERAL OVERBURDEN REGULATIONS

Overburden assessment regulations in the Northern Great Plains are constantly being adjusted as new technology becomes available and will be briefly summarized here. The Federal Reclamation Act passed in 1977 indicated that all unsuitable overburden materials must be identified in a project area but left the specific methods to attain this objective up to the States. As a result, each State in the Northern Great Plains has a different set of guidelines.

Physiochemical Assessment

At present, Colorado has the most comprehensive list of required analyses, followed by Montana, Wyoming, and North Dakota (Table 1). Overburden assessment in North Dakota requires only pH and salt hazard evaluation and ignores all trace metals and associated anions. Since each State has a different overburden depositional environment, different geochemical problems exist across the region. Although not presented here, analytical procedures are similar among states for pH and salt hazard evaluation, and some trace metals. Recommended procedures for some trace element analyses differ among States. A recent Office of Surface Mining (1981) publication compiled all current overburden analytical procedures used by the various states.

Sampling Requirements

Most States require that from each drill hole samples be taken of each stratum in overburden and interburden down to the last economic coal seam. Within each stratum, samples are collected in 5- to 10-foot intervals. When strata are less than 2 feet thick they are often not sampled.

The number of drill holes required in a project area varies among States (Table 1). Montana requires that drill holes be spaced not more than 2,000 feet apart in the project area, while other States recommend that drill holes be spaced 2,000 to 5,000 feet apart. Realizing the complexity of the overburden depositional systems in these areas, this intensity of drill holes is probably not adequate to delineate zones of unsuitable materials. This problem will be discussed in a later section.

TABLE 1. OVERBURDEN SAMPLING INTENSITY AND LABORATORY ANALYSES REQUIRED BY STATES IN THE NORTHERN GREAT PLAINS (SUMMARY).

	STATE			
Parameter	Colorado	Montana	Wyoming	North Dakota
Sampling intensity (ft)[1]	Site-specific	2,000	2,000 to 5,000	5,000
Particle size	X	X	X	X
pH	X	X	X	X
SAR (Na, Ca, Mg)	X	X	X	X
Conductivity	X	X	X	X
Saturation %		X	X	
Cu	X	X	X	
Cd	X	X		
Fe	X	X		
Pb	X	X		
Mn	X	X		
Zn	X	X		
Ni	X	X		
Hg	X	X		
Se	X	X	X	
Mo	X	X	X	
NO_3	X	X	X	
NH_4		X		
B	X	X	X	
Ba	X			
CO_3				
CL	X			
Cr	X			
F	X			
K	X			
SO_4	X			
As	X		X	
Acid-base potential	X[2]	X[3]	X	

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[1] Distances given represent spacing of drill holes on a grid system.

[2] Colorado requires sulfur fractionation (FeS_4, organic-S, SO_4-S, total-S) which permits estimating the acid-producing potential.

[3] Montana requires this analysis only on some samples with $pH < 5.5$.

A recent report (Sutton et al. 1981) completed for the Office of Surface Mining presented the state-of-the-art and guidelines for surface coal mine overburden sampling and analysis; it is a useful report for developing or evaluating an overburden assessment program.

OVERBURDEN DRILLING METHOD CONSIDERATIONS

Overburden drilling methods can contaminate the chemical status of samples. When implementing a new drilling program or when reviewing overburden assessment data, it is important to know how different drilling methods can contaminate samples so such problems can be identified and minimized. All overburden assessment reports should include a discussion which accurately describes the drilling methods used to collect overburden samples.

A description of all drilling techniques for overburden sample collection is beyond the scope of this paper. Drilling techniques and equipment are described in detail by Johnson Division UOP (1975). Below, drilling methods are summarized and important considerations regarding sample contamination are presented.

Northern Great Plains Drilling Methods

Almost all overburden samples in the Northern Great Plains are collected with either a rotary core method or with a rotary chip drilling method. Each method has advantages and disadvantages. All overburden drilling is performed with a truck-mounted unit similar to that shown in Figure 6.

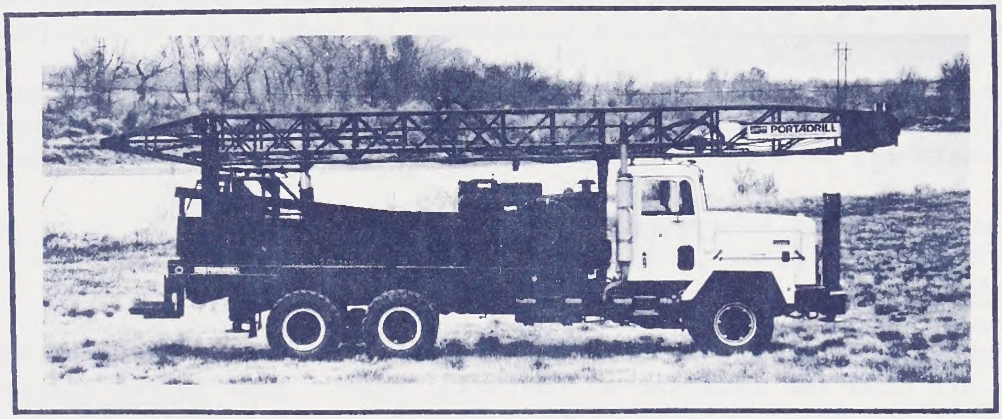

Figure 6. Portable drilling rig used to collect overburden samples.

Rotary Core Method

When initiating a cored drill site, the first 10 to 15 feet of the hole must be removed with some form of rotary chip drilling, which enables insertion of the core barrel. Therefore, this zone should not be identified as cored material in a report.

Continuous coring of overburden is probably the best method to attain high-quality samples. Although it is possible to advance a core barrel through overburden without drilling solutions, the stress on machinery, along with often poor sample retrieval, results in this procedure being used rarely. Usually on-site water is circulated around the drill stem and cutting bit via a sluice box at the surface set around the drill stem. When overburden materials are very porous, this circulating water may permeate rapidly out from the drill hole into the overburden which results in lost circulation. Solution to this problem requires use of a drill hole sealant (mud) mixed into the circulating water. Bentonite (swelling clay) or Revert (organic polymer) is often used for this purpose.

Power and Sandoval (1976) found that the addition of drilling solutions into a hole tends to elevate sample levels of electrical conductivity (EC), Ca, Mg, Na, and sodium adsorption ratio (SAR). The degree of sample contamination was a direct function of the salt content of the water used and also a function of the sealant used. Bentonite, which is often high in sodium content, elevated SAR levels of samples an average of six units. Saline drilling water (5mmhos/cm) elevated sample EC levels as much as 1.0 mmhos/cm. At mine sites, sample contamination could result in some stratigraphic units being determined unsuitable for reclamation.

The contamination measured by Power and Sandoval (1976) was a result of the drilling solution permeating into the cylindrical core only a fraction of an inch. If the inner core material could be used for chemical analysis, excellent data would be attained.

In the Northern Great Plains, core drilling is approximately 15 times more expensive and perhaps 10 times slower than chip drilling with air. Therefore, substantial costs are saved if rotary chip drilling can be used in a project area.

Rotary Chip Method

This method utilizes a large air compressor mounted on the drilling platform which forces air down the interior of the drill pipe. This forced air exits the pipe through the drill bit and blows cuttings to the surface via the space between the drill pipe and overburden wall. Power and Sandoval (1976) found that this method contaminated samples less than coring methods when solutions were used. Since chip drilling with air is the least contaminating, fastest, and least expensive, this method is recommended for overburden sample collection when geotechnical conditions are favorable.

The rotary chip drilling method is often criticized (Sutton *et al.* 1981) for two reasons, neither of which can be substantiated. First, some feel it is difficult to determine the sample depth, since materials are blown to the surface. However, distance markings on the drilling mast can easily overcome this problem. Second, concern exists that a sample blown to the surface from the 50- to 55-foot depth, for example, will erode the hole wall above and be contaminated with these materials. However, assuming drill hole caving is not a problem, such hole wall erosion is insignificant.

If overburden materials tend to cave in the drill hole, mud (e.g., water plus Revert) is generally used to solve the problem. In this case, chip samples would be brought to the surface via the circulating water-mud solution. Under these circumstances the potential for sample contamination is very high. All materials are saturated with the drilling solution, rather than just the exterior portion of a core described above. Also, sample mixing between depths is a problem. Therefore, chip drilling with assistance from mud should be avoided. Although rarely performed, and quite expensive, an alternative is to case the drill hole with pipe to prevent caving.

Reverse Circulation Rotary Drilling-Dual Wall Pipe

Although rarely used in the Northern Great Plains, this method may be the best compromise between accurate sampling and costs. Air is forced down the exterior pipe and cuttings are blown to the surface in the interior pipe. Air pressure cannot be lost into overburden fractures or voids, and sample contamination from caving or erosion of particles from the hole wall is eliminated.

Contamination from Drilling Grease

Drill stem joint greases perform two main functions: 1) the petroleum base acts as a sealant on each joint so air and drilling solutions moving through each pipe stem do not leak out, and 2) the additives such as metal flakes resist galling or metal wear by serving as a physical barrier between metal surfaces and also resist excessive tightening of the joint. The petroleum-base grease generally used for overburden drilling contains Zn, Cu, or Pb metal flake additives. These metal flake additives constitute 10 to 60 percent of the grease on a weight basis.

Dollhopf *et al*. (1981) have shown that drilling grease can contaminate overburden samples (Fig. 7). Upon tightening a joint, small amounts of grease are squeezed into and out of the pipe joint and eventually mixed with cuttings when blown to the surface. The result is an extremely elevated trace metal level in overburden samples for the parameter used as a metal flake additive in the grease (e.g., Pb).

The problem escalates, since Cu, Cd, Fe, Pb, Mn, Zn, and Ni are all suspect when a sample is contaminated with drilling grease (Dollhopf *et al*. 1981). In the Northern Great Plains the concentrations of all these elements are determined from the same DTPA extraction (Norvell and Lindsay 1972). DTPA is an amino acid-chelating agent with a limited number of extraction sites. If these extraction sites are nearly saturated with a single trace metal due to grease contamination, the DTPA cannot accurately extract the other six trace metals.

At present, there is no drilling grease available that has been proven to be non-contaminating. Non-metalic drilling greases are commercially available and may be acceptable. At least one Northern Great Plains overburden assessment was performed using Vaseline as the drilling grease. No sample contamination was present. The Office of Surface Mining has contracted Montana State University to identify a grease that would be suitable for overburden sampling. These results will be available in the spring of 1983. In the meantime, drilling grease with metal additives should be avoided.

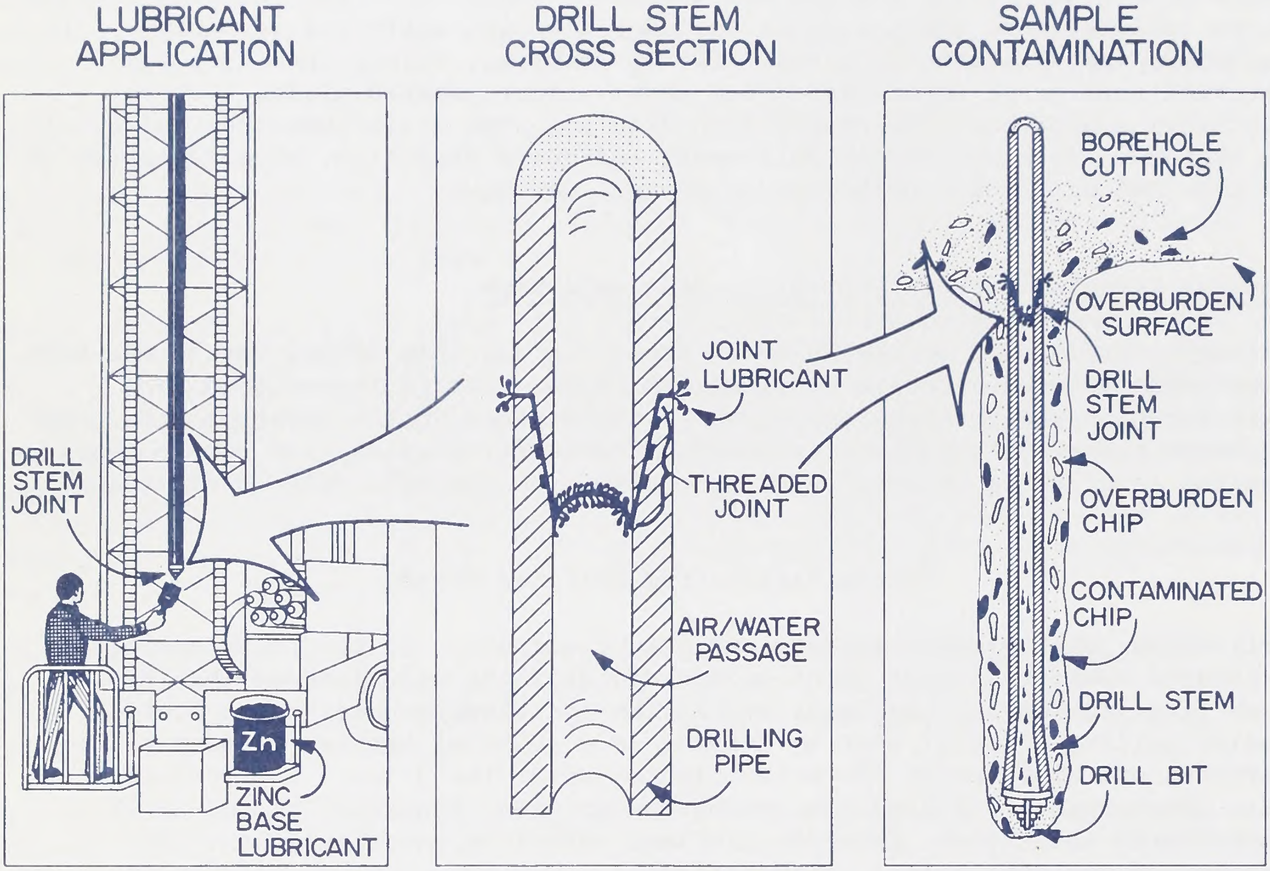

Figure 7. Illustration of overburden sample contamination from drill stem lubricants (from Dollhopf *et al*. 1981).

Although contamination from drilling grease is most pronounced in rotary drilling with air, core drilling methods are susceptible to the same problem. All overburden assessment projects should clearly document the drilling grease used as well as the drilling method used for sample collection.

Overburden Sample Storage

Overburden samples should be air dried (<120° F) as soon as possible after field collection. Similarly, samples should be submited to the laboratory for analysis soon after collection. This will prevent samples from becoming suspect due to long-term storage environments of freezing, heat, spillage, rodent infestation, and unknown effects of time on sample chemistry.

After laboratory analysis, all samples should be stored in a dry environment for the duration of the mine permit application process.

OPTIMUM OVERBURDEN SAMPLING INTENSITY

The Surface Mining Control and Reclamation Act repeatedly indicates unsuitable (toxic) overburden materials must be handled so as not to limit reclamation of the plant, soil, and water resources. Accurate delineation of inhibitory overburden zones at a mine site is a technological problem.

Methods in Use

At present, State regulatory agencies recommend overburden-interburden assessment be performed with drill holes spaced 2,000 to 5,000 feet apart. A recent report submitted to the Office of Surface Mining agreed with this sampling intensity (Sutton *et al*. 1981). With these intensities, a mine may move overburden for several years based on physiochemical results from only two or three drilling sites. However, research indicates drill holes 2,000 to 5,000 feet apart are not capable of delineating zones of unsuitable overburden material.

Drilling Intensity Studies

U.S. Geological Survey

Work by the U.S. Geological Survey (Hinkley *et al*. 1978) indicated that almost as much information about overburden chemistry can be obtained from a single hole drilled anywhere on the mine site as can be obtained from many holes spaced at distances greater than 2,000 feet. The stratigraphy and geochemistry were so variable between boreholes at these distances that the lateral and vertical extent of unsuitable overburden materials could not be determined. Therefore, it may be futile to plan selective overburden handling operations based on holes drilled according to current guidelines, since accurate extrapolation of physiochemical characteristics between boreholes 2,000 to 5,000 feet apart is not possible.

Montana State University

Research by Dollhopf *et al*. (1981) agreed in principle with the results of the U.S. Geological Survey study (Fig. 8). That is, many drill holes in a project area spaced 2,000 feet apart (55 percent accuracy) were not much better than a single drill hole (50 percent accuracy). Ideally, in biological-environmental systems we would like to make correct evaluations at least nine times out of ten, meaning a 90 percent accuracy. If we apply this criterion to the curve presented in Figure 8, we see the required drilling intensity approaches a 100- to 200-foot sampling grid.

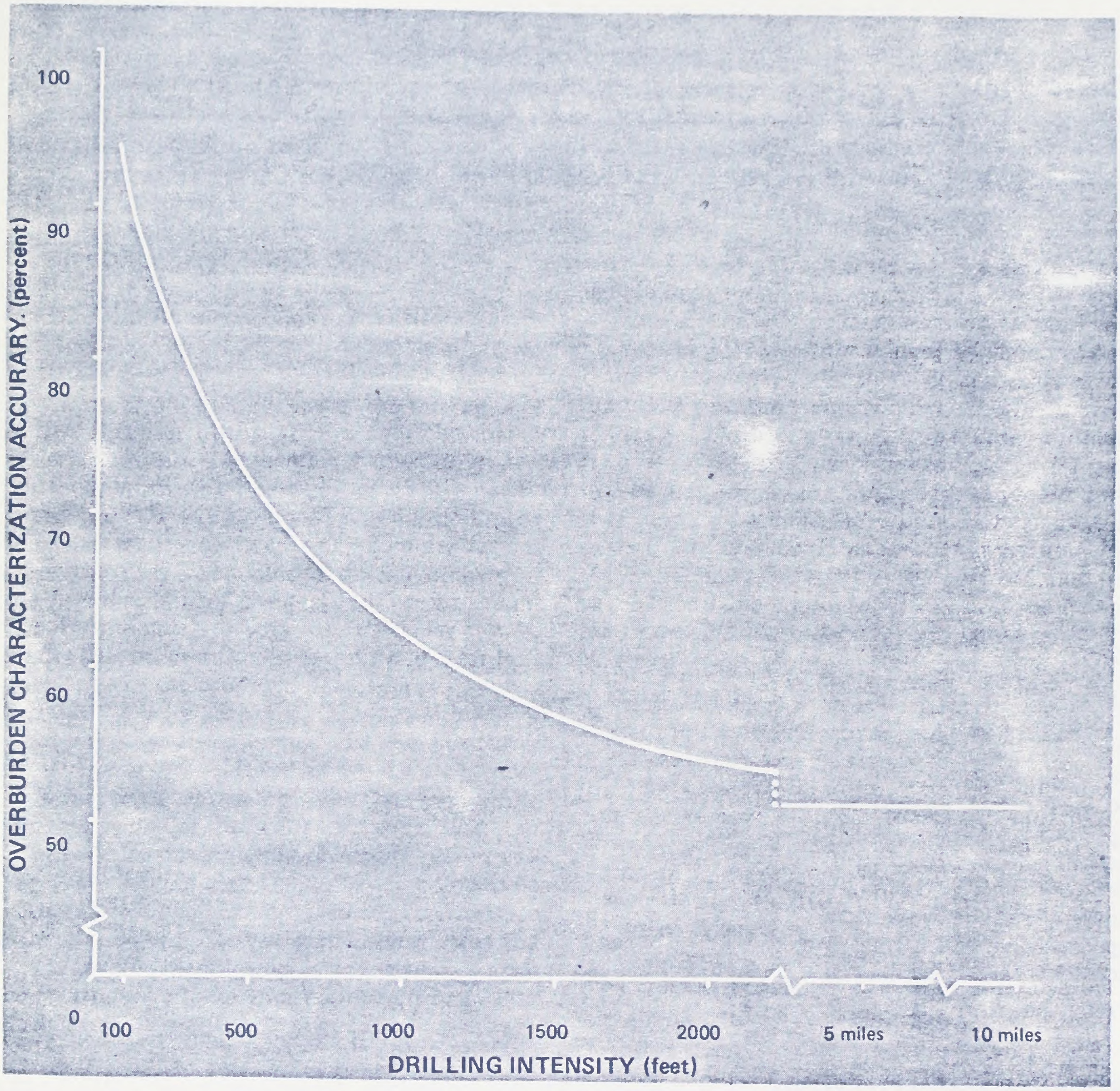

Figure 8. Summarized relationship between accurate overburden assessment and drill hole sampling intensity (from Dollhopf, 1979).

Costs of sampling the overburden to assure all unsuitable materials have been delineated (90 percent accuracy) would skyrocket into millions of dollars compared with several hundred thousand dollars for today's typical Western strip mine operation. Sampling the overburden in two steps may provide a desirable compromise between accuracy and cost. For example, the overburden at a mine site could first be sampled on a 2,000-foot grid. This would not provide good accuracy for delineating the location and extent of inhibitory materials, but it would very likely identify the overburden chemical and physical parameters present at inhibitory levels. Then the entire area would be drilled intensively to attain an accuracy of 80 to 90 percent--i.e., a 200-foot grid--but these samples would be analyzed only for those parameters present at inhibitory levels in the initial reconnaissance. Approximately 15 percent of the cost would be for drilling services, and the remaining cost would be for sample analysis. Thus, a twofold approach as described above could decrease overburden characterization costs substantially.

Considering that Western States now sample overburden in a 2,000- to 5,000-foot grid, it is likely that incorrect interpretations are being made, resulting in inhibitory materials being unknowingly deposited either in the future aquifer zone or the root zone. Mine sites that implement special overburden handling procedures based on drill holes spaced more than 2,000 feet apart are probably handling materials incorrectly 50 percent of the time, since unsuitable materials are delineated with only a 50 percent accuracy.

Hope For The Future

A recent study which assessed the feasibility of developing a toxic overburden detection system (Bruhn et al. 1980) found that the technology was not present for a detection system operating from the surface but indicated that certain downhole probes utilizing physical chemistry approaches were feasible. Development of a downhole probe that incorporates natural gamma, neutron activation, gamma-gamma, temperature, caliper, induction, pH, and spectral analysis should, when fully refined, be capable of providing immediate on-site delineation of unsuitable overburden materials. Borehole drill costs would still be present, but the cost of wet chemical analysis of samples could be largely deleted. Such a development would make intensive (90 percent accuracy) overburden sampling more feasible.

Overburden Sampling Geometric Considerations

It is common practice to divide a mine project area into a square grid system on a base map so that lines of division are parallel to the existing township-range legal description system. Boreholes for sampling the coal seam and overburden physiochemical characteristics fall into this square grid system. Since overburden is generally sampled every 2,000 feet in Western States, a square grid pattern is usually produced with boreholes 2,000 feet apart (Fig. 9A).

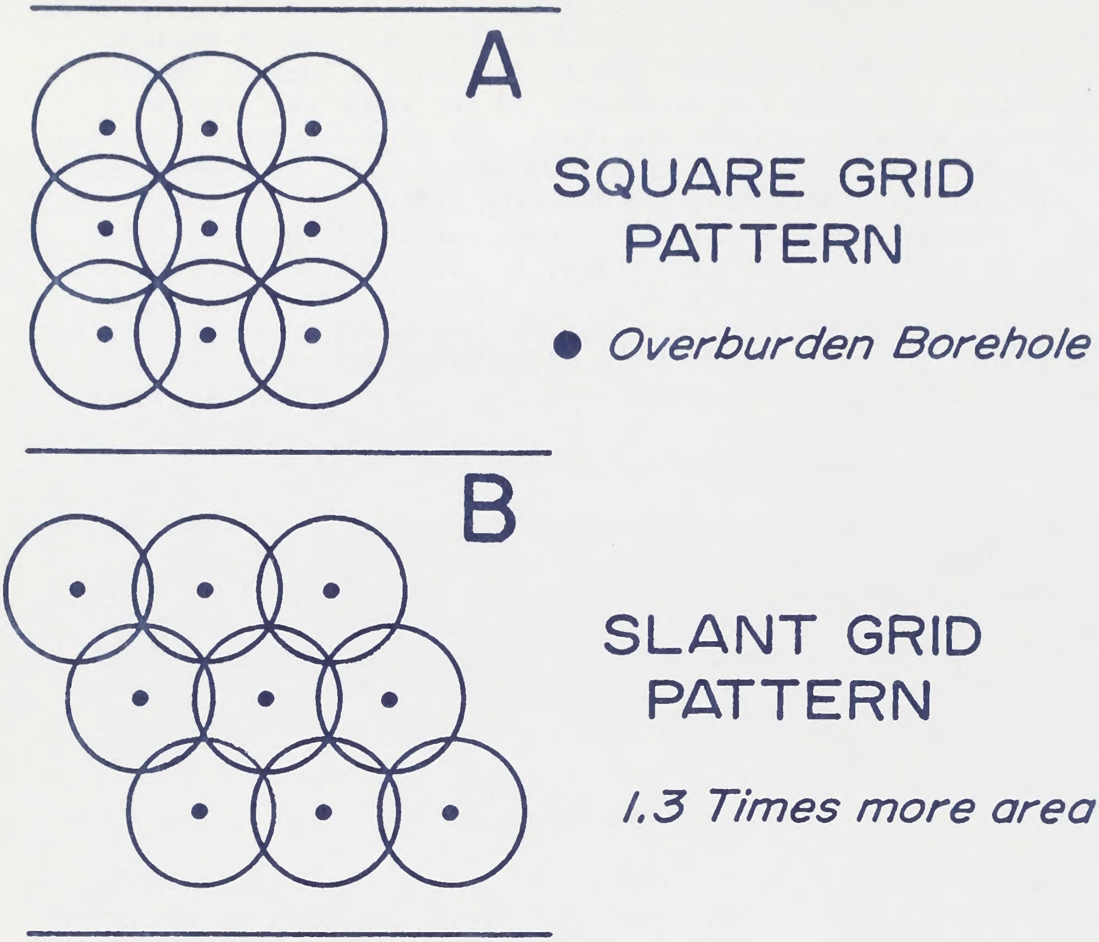

Figure 9. Square grid vs. slant grid drilling patterns for overburden characterization.

When a 2,000-foot square grid is implemented in a project area, it infers that physiochemical results from each borehole must be extrapolated concentrically outward 1,395 feet (radius). This result is shown in Figure 9A, where the circular zone of data extrapolation around each borehole (2,790-foot diameter) must exceed the borehole spacing (2,000 feet) to provide complete coverage of the project area.

If we assume each borehole in the square grid pattern is representative of overburden material within a radial distance of 1,395 feet, then these same boreholes could be arranged into a 60° slant grid pattern (Fig. 9B) which would cover 1.3 times more project area than the square grid pattern (Dollhopf et al. 1981). The boreholes are spaced 2,411 feet apart in the slant grid pattern, thereby providing greater project area coverage than with a 2,000-foot spacing, yet all portions of the project area are covered with the same 1,395-foot radial distance for extrapolation of data from a central borehole.

When a project'area is drilled intensively to attain a characterization accuracy of 80 to 90 percent--i.e., a 200-foot grid--a slant grid pattern could be implemented with boreholes 240 feet apart, resulting in efficient overburden characterization with a 30 percent savings in drilling and laboratory costs.

SELECTIVE BURIAL OF UNSUITABLE OVERBURDEN

The Surface Mining Control and Reclamation Act repeatedly indicates unsuitable (toxic) overburden must be specially handled so as not to limit reclamation of the plant, soil and water resources. Although the intent of the law is clear, performing selective handling is often prohibitively expensive, and at times the technology is lacking.

Selective Handling in the Northern Great Plains

Selective handling of unsuitable overburden materials can be separated into two categories. The first, and most commonly practiced, is to segregate the same stratigraphic unit throughout the mine area. In Montana, this is being performed at two mine sites where interburden materials are being selectively placed below the future root zone but above the pit base where an aquifer tends to reestablish. The second category is when discontinuous zones of unsuitable overburden materials are encountered and handled, specially. This is not being practiced in the Westeren States, even though most mine sites contain a greater volume of unsuitable material in overburden than in interburden, which is specially handled at some mines. This situation has developed from an inability to accurately locate these unsuitable-discontinuous zones in overburden, and from the difficulty in implementing a mine plan where the overburden handling technique would be in a constant state of change as different shapes and volumes of unsuitable materials were intercepted.

Dollhopf _et al_. (1981) demonstrated the principles of a selective handling operation with a dragline (Fig. 10), where saline material in the upper one-third of the overburden was buried below the surface but above the pit base (Fig. 11). Although the suitable and unsuitable overburden was located at different depths, the dragline had the ability to dig these materials selectively. A shovel in a truck-shovel operation would have difficulty selectively digging these materials.

Premining Assessment

To implement a successful selective handling operation, the location of unsuitable materials must be accurately known, and the postmining groundwater levels must be accurately estimated. A year or more of monitoring of local aquifers is necessary to be able to predict thickness of the reestablished spoil aquifer. This is a necessary step to assure that unsuitable mateials are buried above the aquifer.

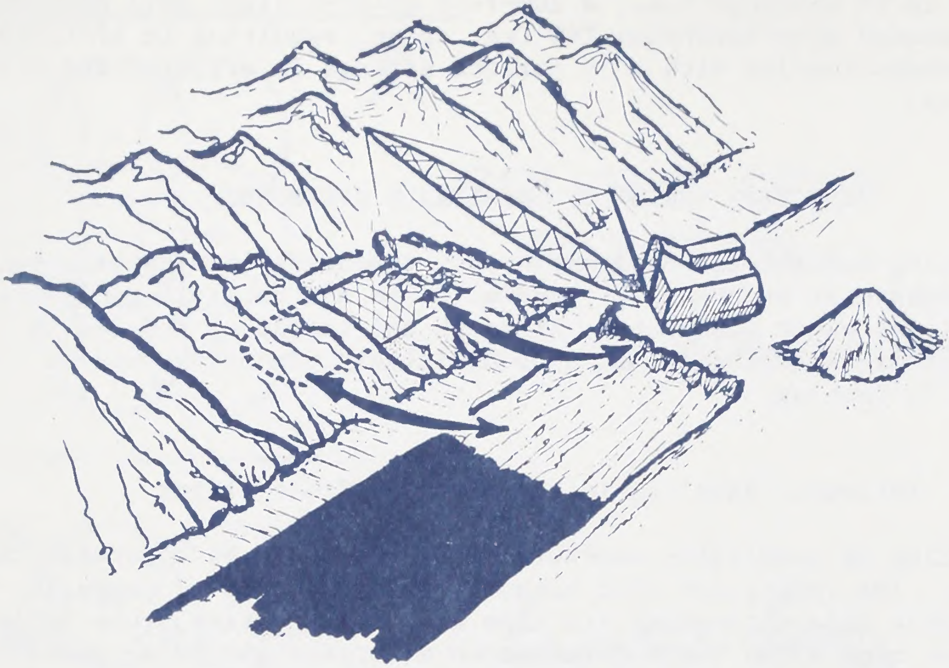

Figure 10. Burial of saline overburden (upper arrow) with good quality material (lower arrow) (from Dollhopf et al. 1981).

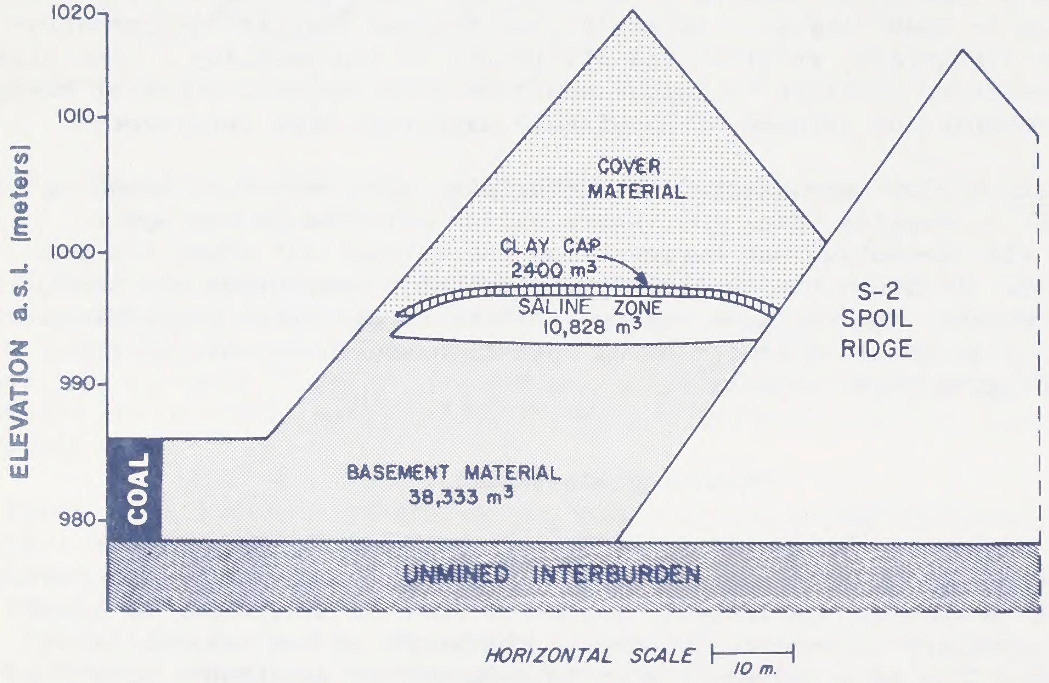

Figure 11. Saline material buried by dragline in backfill area below future root zone and above aquifer zone that reestablished over the pit base (from Dollhopf et al. 1981).

Accurate delineation of unsuitable overburden zones remains a technical problem. The complex depositional systems found in the Northern Great Plains make overburden geochemistry highly variable. Necessary sampling intensities are discussed in a later section.

Clay Cap Construction

The Surface Mining Control and Reclamation Act indicates buried toxic material should be clay-capped when necessary. The intent is to divert downward percolating waters around the burial sites, so that leaching of toxic chemistry into groundwater is prevented.

Dollhopf *et al*. (1981) constructed a 3-foot-thick clay cap with scrapers over buried saline material at one coal surface mine in the Northern Great Plains (Fig. 12). The clay materials were obtained from a site 3,000 feet away and were compacted to a maximum density of 1.8 g/cm^3. The site was then backfilled by a dragline so that the buried material was above the aquifer zone but below the root zone. In the final postmining landscape the burial site was located beneath a slope, rather than beneath a hilltop or valley bottom. After 3 years of hydrologic monitoring, it was determined that unsaturated water movement occurred from the surface to the buried saline material during wet spring periods. However, the quantity of flow was not substantial and no significant leaching of salts from the buried saline material, either clay-capped or not capped, was expected. Therefore, construction of clay caps over buried material in the semiarid Western States may not be necessary. This is true when the burial site is positioned beneath a hilltop or slope in the mined landscape. If the burial site has to be constructed in a valley bottom, or other land feature that would collect water, then a clay cap may be advisable.

Dollhopf *et al*. (1981) showed properly constructed clay caps can be an effective barrier to water flow. Materials used for a clay cap should have at least 40 percent of the particles greater than 0.002 mm and be dominated by a smectite (swelling) clay mineralogy rather than illite or kaolinite. A Proctor test (ASTM D698, method A) is necessary to relate compactable density to water content of the clay. The clay materials may need to be dried or irrigated to attain the optimum water content for maximum compaction density.

Cost of Selective Handling

One common denominator shared by all selective handling operations is that they are more expensive than normal operations. Dollhopf *et al*. (1981) determined that selective burial costs about $15,000/acre to handle the overburden, compared with $10,000/acre for normal burial. When buried material was clay-capped, costs to handle the overburden rose to $30,000/acre, a 300 percent increase over the normal operation. These values will fluctuate notably given different overburden conditions and machinery, but they put into perspective the added expense associated with selective overburden handling.

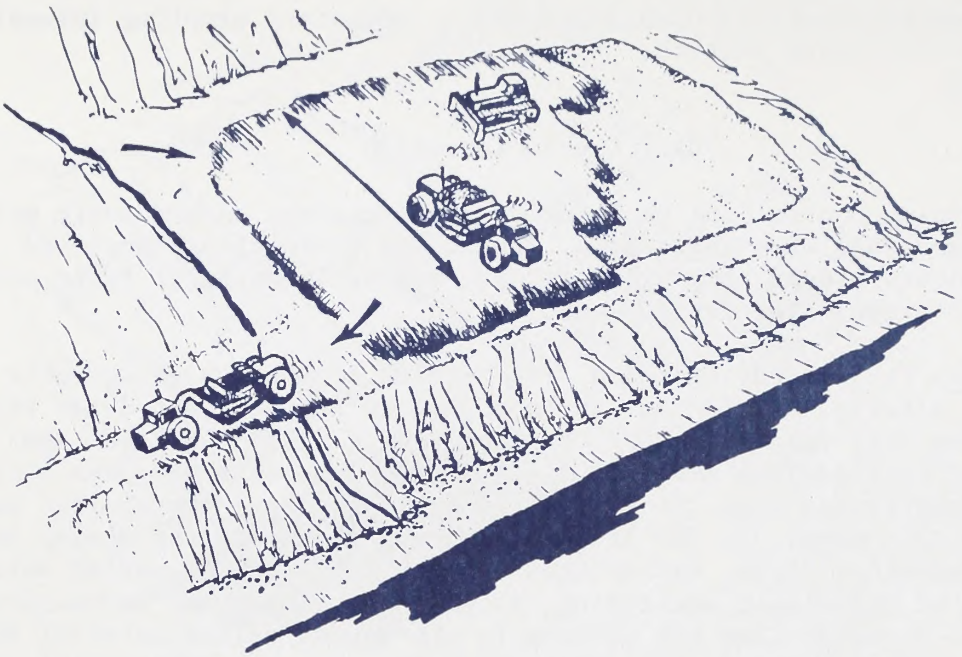

Figure 12. Clay-cap construction over toxic material, all of which sits atop 40 feet of spoil material where aquifer reestablished above pit base (from Dollhopf et al. 1981).

Because of these high costs, selective handling is looked upon as a last resort in the reclamation plan. Alternatives include spoil mixing, where toxic materials can be diluted during the backfill process, as described in the following section.

SPOIL MIXING PHENOMENA

Selective burial of overburden materials to hydrologically isolate them may cost 1.1 to 1.5 times more than the normal spoiling operation, as discussed in the previous section. Before such methods are practiced it may be well to determine whether normal dragline spoiling can sufficiently mix problem overburden material to produce an environmentally acceptable spoil profile.

Mixing Principle

Overburden material that is considered chemically or physically unsatisfactory for reclamation can sometimes be mixed with material that is desirable. For example, a surficial overburden zone with a high concentration of lead, e.g., 15 ppm, may be mixed during the dragline spoiling process with material at a lead concentration of 1 ppm, resulting in a spoil pile lead concentration ranging between 3 and 5 ppm. This resultant spoil material if left near the surface would not be harmful to plant growth, nor would it, if left at the pit base where an aquifer may develop, tend to give the water a higher lead concentration. This principle would similarly apply to overburden physical parameters, such as sand and clay content.

In the laboratory, the spoil mixing phenomenon can be proved to be a linear relationship. This means if 50 cubic yards of overburden with 60 percent clay content are mixed with 50 cubic yards of overburden with 10 percent clay content, the result will be spoils having a 35 percent clay content. However, a dragline or truck-shovel operation can't mix the overburden stratigraphic units perfectly. The efficiency with which overburden can be mixed by machinery is a topic of heated discussion in the Northern Great Plains.

Field Studies

At present there is only one field study where spoil mixing results with a dragline were documented. Dollhopf et al. (1979) found that when inhibitory material constituted less than 5 percent of the total overburden volume, such material was essentially not detectable in the resultant spoil pile due to mixing/dilution processes. When inhibitory material exceeded 15 percent of the overburden volume, it was always found in the resultant spoil pile, generally to a lesser extent, indicating partial dilution. These results were obtained near Colstrip, Montana, in 40 to 60 feet of overburden composed of intermixed beds of sandstone and shale. A dragline was used with a 60 cubic yard bucket and a 325-foot-long boom, which allowed a versatile working radius of 286 feet.

These results can be used as a guideline until new studies at mines with different overburden characteristics and machinery advance our understanding of the spoil mixing process. Based on field observation associated with the digging mode, it seems probable that a truck-shovel operation has a somewhat greater potential to mix overburden materials than a dragline.

Dragline and Truck-Shovel Digging Method

Initial bucket cuts by a normal dragline operation tend to be from surface materials, while later cuts are from the entire overburden section, with some domination by deeper materials (Fig. 13). Therefore, unsuitable materials located near the surface may not mix nearly as well as unsuitable materials deeper in the overburden. Toxic materials deep in the overburden would be mixed with materials from the entire overburden section; this would not be true for surface toxic zones.

Most shovels in the Northern Great Plains are designed to dig a 40- to 50-foot overburden section. If overburden materials were 100 feet thick, two 50-foot lifts would be required. The digging action of a shovel mixes the entire 50-foot overburden section, in a way similar to the deep bucket cuts of a dragline. Thus, the shovel may mix overburden materials somewhat more efficiently.

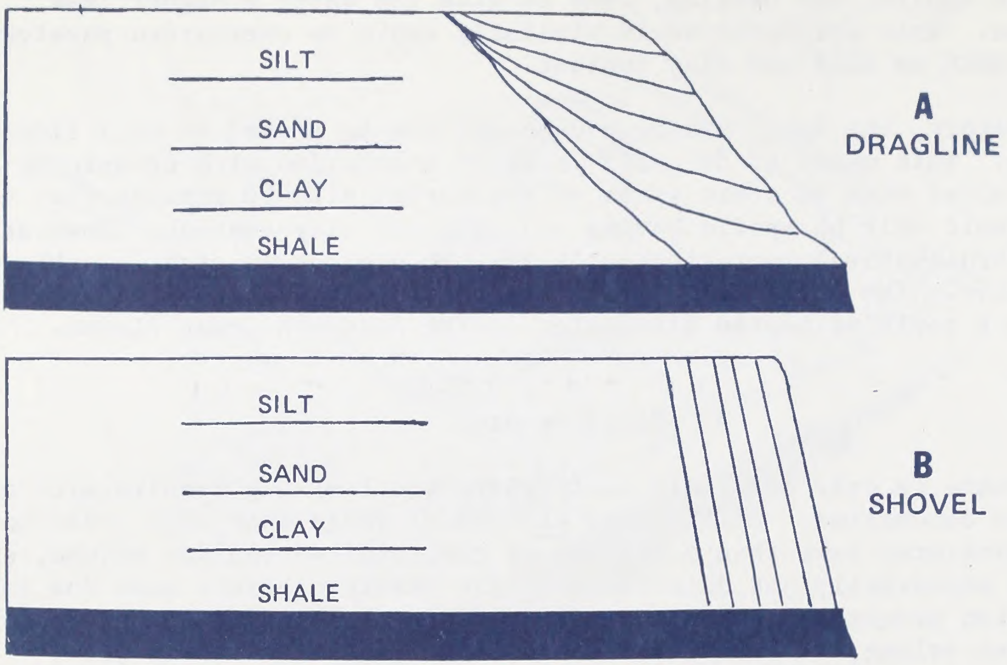

Figure 13. Generalized overburden digging method for dragline (A) and shovel (B).

Secondary Mixing

A dragline has the ability to scatter the contents of the bucket over a much greater area than that from which the bucket was filled (Fig. 14A). This scatter spoiling technique is a method of diluting the bucket contents. The material is diluted further as materials cascade tens of feet down the side of the spoil piles.

In a truck-shovel operation, secondary mixing occurs in the truck box and when the materials are dumped by the truck. Secondary mixing in a truck-shovel operation is probably not as great as with a dragline.

In summary, the spoil mixing phenomena cannot be easily modeled with mathematical variables and solutions. Careful field studies are needed at many mines in the Northern Great Plains to evaluate the many variables controlling the spoil mixing process.

Overburden Inversion

In a dragline operation it is often assumed that the overburden stratigraphic sequence is basically inverted in the resultant spoil pit. This means surface overburden materials end up in the pit base and vice-versa. Such a process does not actually occur.

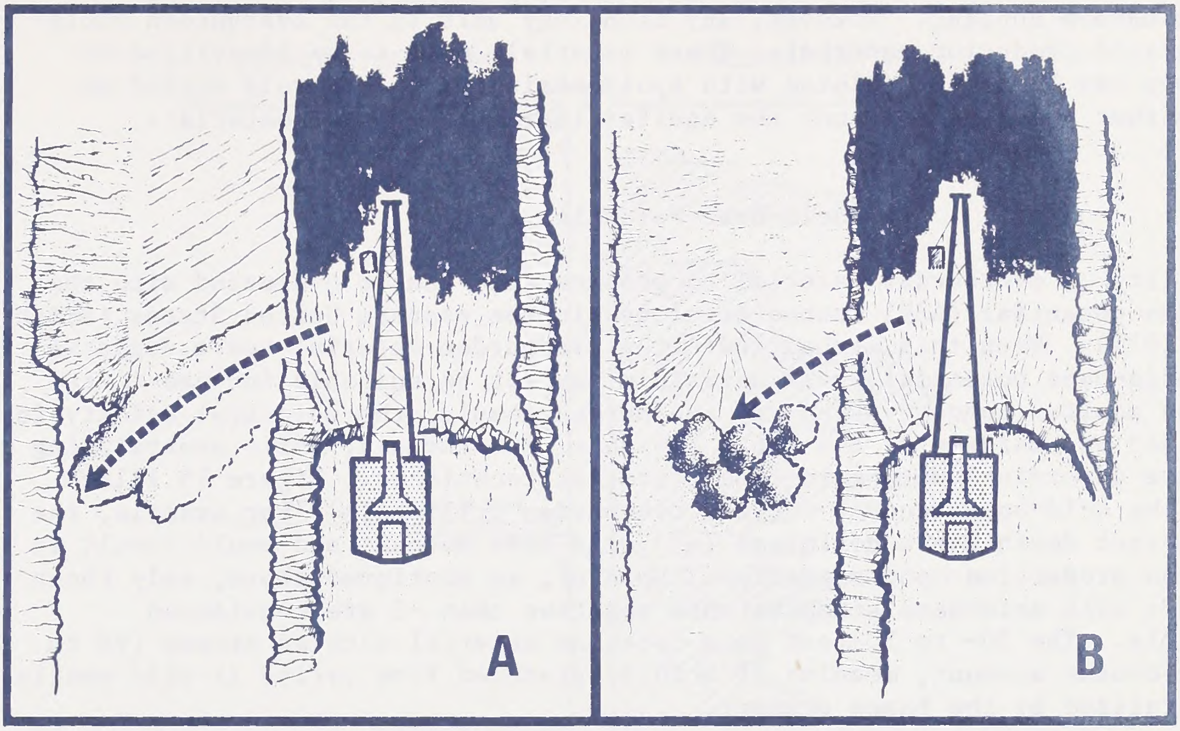

Figure 14. Aerial view of dragline performing scatter spoiling (A) and dump spoiling (B) (from Dollhopf et al. 1979).

As discussed earlier, there is a tendency for a dragline to initially fill its bucket with surface overburden materials. These materials may be deposited in the pit base, but they are just as likely to be cast high in the spoil pile. It is a poor assumption to say that there is even a tendency for overburden to be inverted in the spoiling process.

ACID-PRODUCING OVERBURDEN

Overburden-interburden materials in the Northern Great Plains generally have an alkaline pH due to an excess of carbonates. However, often certain stratigraphic units have neutral or acid pH levels. If these zones contain pyrite (FeS_2), they may produce very acid soil materials upon oxidation when uncovered and exposed to an oxygen-rich atmosphere (Equations 1, 2, and 3):

$$2\ FeS_2 + 7O_2 + 2\ H_2O = 2\ Fe^{2+} + 4\ SO_4{}^{2-} + 4\ H^+ \qquad (1)$$

$$Fe^{2+} + 0.25\ O_2 + H^+ = Fe^{3+} + 0.5\ H_2O \qquad (2)$$

$$Fe^{3+} + 3\ H_2O = Fe(OH)_3 + 3\ H^+ \qquad (3)$$

Such acid-producing materials are often associated with carbonaceous zones, meaning dark-colored units containing coaly fragments and having a high organic carbon content. However, any lithology unit in the overburden could contain acid-producing material. These materials need to be identified so that they can be either diluted with spoil mixing or selectively buried so that neither the root zone nor the aquifer ineracts with the material.

Acid-Base Potential (ABP)

The ability of overburden material to produce acid can be evaluated with the acid-base potential (ABP) method developed in the eastern United States (Smith et al. 1974). When this method indicates overburden material has a negative (<-5) acid-base potential, such materials may not be suitable for use in the root and aquifer zones. Given any overburden sample, the potential acidity is determined by analysis of the total S with a LECO furnace, while neutralizing bases are determined with acid-base titration techniques. Figure 15 illustrates the acid-base account for one overburden drill hole. For example, the 0- to 4-foot depth has a deficient (-3) acid base account and would result in some acid production upon oxidation. However, as mentioned above, only those materials with acid-base accounts more negative than -5 are considered unsuitable. The 20- to 30-foot zone contains material with an excess (+8 to +60) acid-base account, meaning if acid is produced from pyrite it will easily be neutralized by the bases present.

Materials immediately above and below the coal seam have very negative (-15 to -110) acid-base accounts, meaning some bases may be present, but pyrite is present in such quantities that these materials will become very acid upon oxidation and may limit plant establishment.

At present, Wyoming requires this test on all overburden samples. Other States do not require this analysis routinely, but if samples have a low pH the acid-base account is often determined.

Methodology Problems for Western Overburden

Source of Acid-Producing Sulfur

In overburden materials, sulfur is present in mainly three forms: 1) pyrites, 2) organic-S, and 3) SO_4-S. Sulfate-S is fully oxidized and is not of concern regarding acid production. Although not fully understood, organic-S is quite inert and is capable of producing only small quantities of acid upon oxidation. Pyrite (FeS_2) as well as marcasite (FeS_2) are capable of generating acid upon oxidation, according to previously presented equations 1 through 3. Therefore, only overburden pyrite-S can produce acid problems that may limit reclamation success.

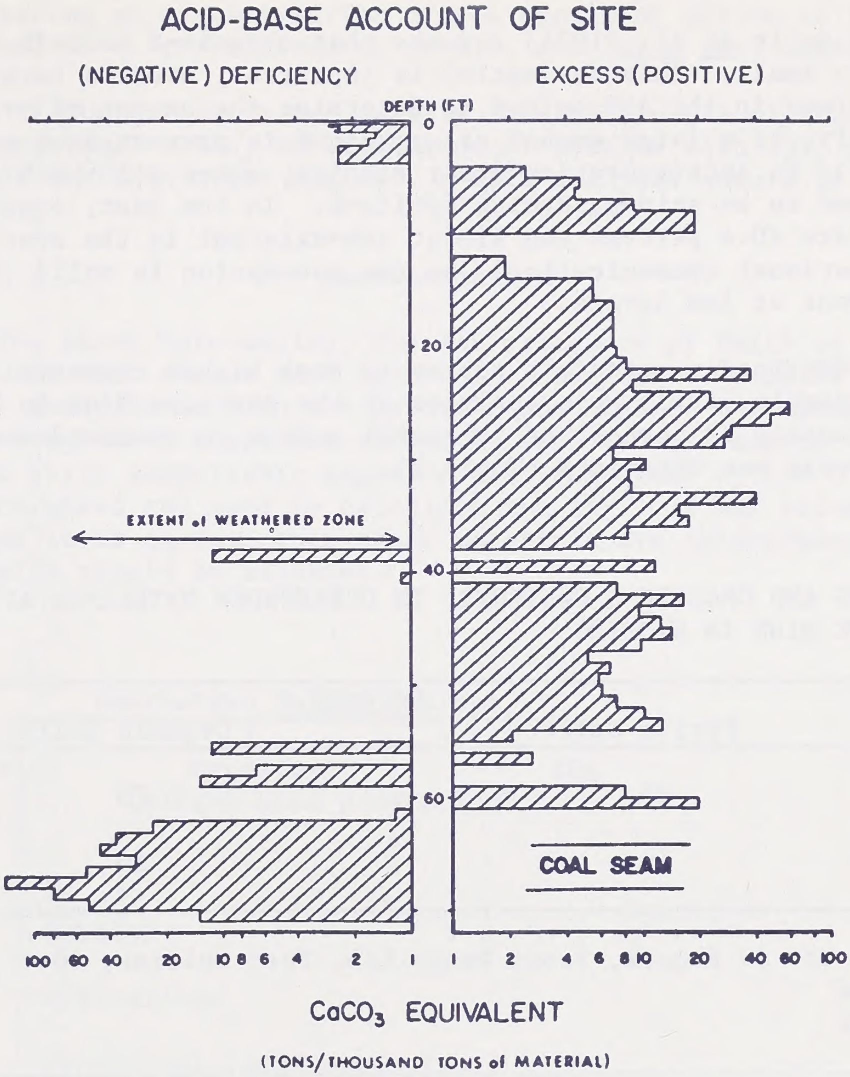

Figure 15. Acid-base account illustrating net acidity or alkalinity through single overburden drill hole (from Smith _et_ _al_. 1974).

However, studies in the eastern United States have shown that some mines with high pyrite-S contents don't have acid problems, while other mines with high pyrite-S do have acid problems (Caruccio 1968). In samples from non-acid-producing mines, the pyrite commonly had a massive form >400 μm in diameter. Crystals of pyrite having cubical or triangular shapes (5-10 μm) were also found to be inert at these sites. Overburden from acid-producing mines, however, contained pyrite as small spheres (<25 μm diameter) of framboidal pyrite which was much more reactive than massive pyrite. It is believed that only the framboidal pyrite can cause notable acid production at a mine site (Caruccio _et_ _al_. 1977). The framboidal pyrite represents only 10 to 60 percent of the total pyrite at sites in the eastern United States.

Organic-S Considerations

The ABP method of Smith et al. (1974) assumes that organic-S content in overburden is very small. This assumption is important, since a total-S analysis is performed in the ABP method to determine the amount of pyrite-S present. Obviously, if a large amount of organic-S is present in a sample (e.g., 50 percent), an interpretation error results, since all the S (pyrite + organic) is assumed to be acid-producing pyrite-S. In the East, organic-S contents in coal are <0.4 percent and almost non-existent in the overburden (Caruccio 1981, personal communication), so the assumption is valid that organic-S is present at low levels.

However, Western overburden materials appear to have higher contents of organic-S. For example, drill hole analyses at the Antelope Mine in Wyoming indicated approximately 22 percent of the total sulfur in overburden was pyrite and 78 percent was organic-S (Table 2).

TABLE 2. PYRITE-S AND ORGANIC-S CONTENTS[1] IN OVERBURDEN MATERIALS AT THE ANTELOPE MINE IN WYOMING

	Percent	
Drill Hole	Pyrite Sulfur	Organic Sulfur
1[2]	25	75
2[3]	19	80

[1] Data supplied by Mr. J. Rogers, Front Range Lab, Fort Collins, CO.
[2] Mean of 35 depths
[3] Mean of 20 depths

This means that the acid-producing potential would be overestimated by a factor of at least 4, since the total-S analysis required by the procedure of Smith et al. (1974) looks upon all the organic-S as producing as much acidity as pyrite-S. The ABP method simply doesn't differentiate between pyrite-S and organic-S, even though the pyrite-S produces nearly all the acidity.

Organic Matter Considerations

The ABP procedure provides two options for determining the acid-producing potential of overburden samples. Laboratories equipped with an expensive LECO analyzer can determine the total-S content of samples. The less desirable alternative is to measure the potential acidity with peroxide. Here H_2O_2 is added to the sample, which strongly oxidizes all materials, resulting in acid formation from pyrites. The amount of acid produced is determined by titrating with a base.

If organic matter is present in the sample, the H_2O_2 will oxidize this material, creating an overestimation of the amount of pyrite in the sample. This could lead to a very misleading result, meaning a very negative ABP.

Carbonaceous overburden zones may contain notable amounts of organic matter in the form of proteins. Thus, determination of total-S with H_2O_2 should be avoided in the Northern Great Plains. A LECO analyzer should be used instead.

Recommendation

In light of the above information, the ABP procedure of Smith et al. (1974) produces results that are at best uncertain. Overburden samples should be submitted for analysis of both the pyrite-S and organic-S components (Fig. 16). Only the pyrite-S component should be used in determining the ABP value. If values are still undesirably negative the framboidal pyrite-S content should be determined and used to calculate the ABP. If ABP values are still negative, then it is certain that these materials are acid-producing and the reclamation plan should be adjusted.

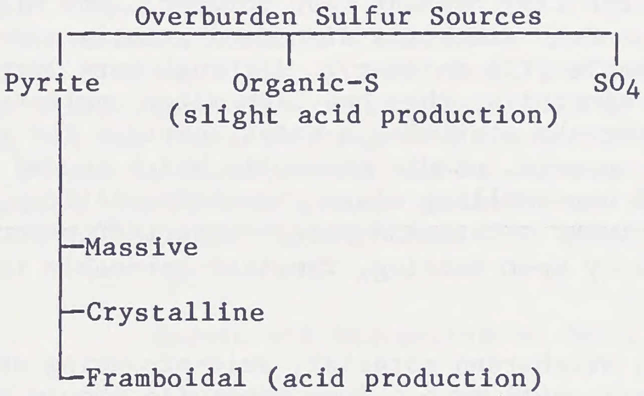

Figure 16. Problem components of acid-producing overburden material.

Analysis of organic-S and pyritic-S should be performed at a laboratory which has a LECO furnace for sulfur determination so that organic matter in samples will not interfere with the ABP determination. The actual method is published as ASTM D24 92-77, where SO_4 is removed with a weak acid wash, total-S is determined with a LECO furnace, pyrite is leached out with HNO_3 for LECO analysis, and organic-S is determined by subtraction.

It appears that neither coal nor overburden materials in Western States have been analyzed for framboidal pyrite content. Such data are very important, since only an estimated 10 to 60 percent of the pyrite is actual acid-producing framboidal pyrite. Caruccio et al. (1977) have described the procedure wherein samples are prepared for microscopic inspection of the pyrite forms present. A count system is utilized to determine the percentage of each pyrite form. University geology departments can perform this work.

Field Management of Acid Materials

Topsoil Acidification

Acid material in the subsoil (regraded spoils) is of concern, since plant root development may be diverted to less acid zones, causing above-ground productivity loss. However, the primary concern is that acidity in spoils may migrate into the topsoil, killing a several year-old plant establishment effort.

This concern parallels the situation in sodic minesoils of the Northern Great Plains, where good quality topsoil is placed over sodic spoils (SAR = 25). At some sites in North Dakota (Merrill _et al_. 1980) the topsoil became sodicated in a few years and plant productivity plummeted. However, other sodic minesoil sites in Montana did not experience upward Na^+ migration and productivity losses (Dollhopf _et al_. 1980). It was determined that the physical characteristics of sodic minesoils dictate whether topsoil sodication will occur.

The principles learned in these studies should apply to the upward migration of H^+ in minesoils. Characteristics that favored upward Na^+ migration were swelling clays (smectite), high clay content (>35 percent), and high saturation percent (>90 percent). Such minesoils dispersed greatly upon wetting and became nearly impermeable (<15 cm/year). Although very little water movement occurred in these minesoils, they had high water contents due to high porosity of clay soils, thereby providing a water corridor for the upward diffusion of Na^+ into the topsoil. Sodic minesoils which tended not to undergo topsoil sodication had non-swelling clays (kaolinite-illite), lower clay contents (<30 percent), and lower saturation percentages (<80 percent). These soils did not disperse greatly upon wetting, remained permeable to water, and drained well.

Due to unavailability of suitable overburden material, acid-producing spoils may have to be placed beneath the topsoil zone. Such minesoils should be constructed with materials having physical characteristics described above to prevent eventual topsoil acidification.

Spoil Mixing

It would be desirable to be able to simply mix acid-producing materials with materials having an abundance of base chemistry, the result being a soil with a nearly neutral pH. This is certainly possible, but the success of this mixing procedure would need to be proven. The ability of an operator to dilute unsuitable overburden materials during the spoiling process was discussed earlier.

SPOIL STABILITY AND SUBSIDENCE

Once the overburden has been cast or dumped into spoil piles, the material begins to settle. If differential settling occurs, the postmining landscape will be ruptured and surface drainage-erosion problems will be enhanced. Such problems can be minimized with proper management during the spoil pile grading process (Groenewold and Rehm 1979). A basic understanding of these disturbances is necessary for developing a spoil contouring and reclamation plan.

Types of Instability

Surface instability on postmining landscapes can take three forms: 1) areawide settling, 2) localized collapse, and 3) piping. Areawide settling usually occurs during the first year after contouring and represents settlement of 1 to 3 feet. This type of subsidence generally results in very little disruption of the surface. Areawide settling is due largely to the overburden swell factor of 15 to 35 percent in the Northern Great Plains. After spoiling, the unconsolidated materials undergo natural settling due to the forces of gravity. To a small degree, areawide settling is controlled by contouring methods, as will be discussed later.

Differential subsidence or collapse of the surface of the spoils and piping failures is the most dramatic instability phenomena. Localized collapse is often 50 feet in length and 10 feet deep, and this problem generally occurs during the first year after contouring. Piping may develop soon after contouring but may begin as long as 5 years after recontouring. Pipes are generally 3 feet in diameter and may be as deep as the spoil fill, e.g., 100 feet. Surface runoff from either snowmelt or rainfall may drain into these pipes, carrying valuable topsoil down into the depths of the spoil fill.

Causes and Prevention of Spoil Instability

The textural characteristics of the original overburden can be expected to have a marked influence on settlement. Fine-grained overburden commonly results in more blocky and more porous spoils than does sandy overburden. Less settlement in areas of largely sandy spoils can be expected.

Both the equipment used and the time of the year are key factors in controlling spoil instability problems. Groenewold and Rehm (1979) showed that settlement is significantly less in scraper-contoured areas than in dozer-contoured areas, particularly if contouring occurred in midwinter when materials were frozen. Localized collapse occurred only in precontoured valley areas where frozen materials were graded with a dozer. Dozer contouring of frozen spoils concentrates large blocky fragments in valley areas. Settlement and thawing in areas where the frozen blocky materials have been concentrated apparently is the cause of localized collapse at the surface. In contrast, areas contoured with a scraper in midwinter are extremely stable. In the Northern Great Plains, localized collapse can be avoided if dozer contouring is restricted during winter months.

Piping is controlled by a combination of physical and chemical conditions in the spoils. All piping begins as a crack in the topsoil-spoil root zone. Highly dispersive sodic materials with high clay content are especially suited to develop large cracks. However, piping will develop only if an avenue for water movement is present beneath the root zone. Such an avenue can result from backfill fracturing due to differential settling between areas compacted differently. Such fracturing results from differential settling between very stable dragline-deposited spoils and loose fill (uncompacted) in valley areas deposited by dozers, especially in midwinter. In contrast, scraper-deposited valley fill areas are generally devoid of piping problems.

Level areas in the postmining landscape favor piping problems. In these areas, runoff is minimal and infiltration is maximized. At mine sites with piping problems, level areas should be avoided.

In summary, spoil instability will be most disruptive in the Northern Great Plains at mine sites with clayey overburden that is sodic and disperses greatly. Subsidence problems can be minimized by burying sodic materials well below the surface and by not contouring spoil piles in midwinter with dozers.

FINAL MINE CUT PROBLEMS

Project areas often require 10 to 20 years to extract the coal, but eventually the coal crops out or the stripping ratio becomes too great and a final cut is made. The result is a void down to the pit base with a near vertical highwall on the undisturbed side. The overburden from the final cut has been backfilled into the void from the previous mine cut and reclamation of the highwall areas becomes an expensive problem. Such problems can occur frequently during a mine life in project areas that have considerable relief. Intermediate mine cuts may encounter large hills (high stripping ratios), requiring termination of that portion of the cut, so a highwall results. Three potential solutions to the highwall reclamation problem are discussed below.

Haul-Back Method

The initial mine cut creates spoils that have to be placed over undisturbed lands adjacent to the pit. As a mine life matures, successive cuts and backfills move away from initial cut spoils. When a final cut highwall is created the initial cut spoils could be used to fill in the void (Fig. 17). From a reclamation standpoint this is desirable, since surface topography both in the initial and final cut areas will most closely resemble that of the premining condition.

However, the haul-back method is generally prohibitively expensive. At mines which move overburden with dragline, only scraper equipment may be available to haul back materials a distance of several thousand feet or even miles. Truck-shovel operations may have equipment more suitable for the haul-back method, but costs are still very high to fill in a final cut.

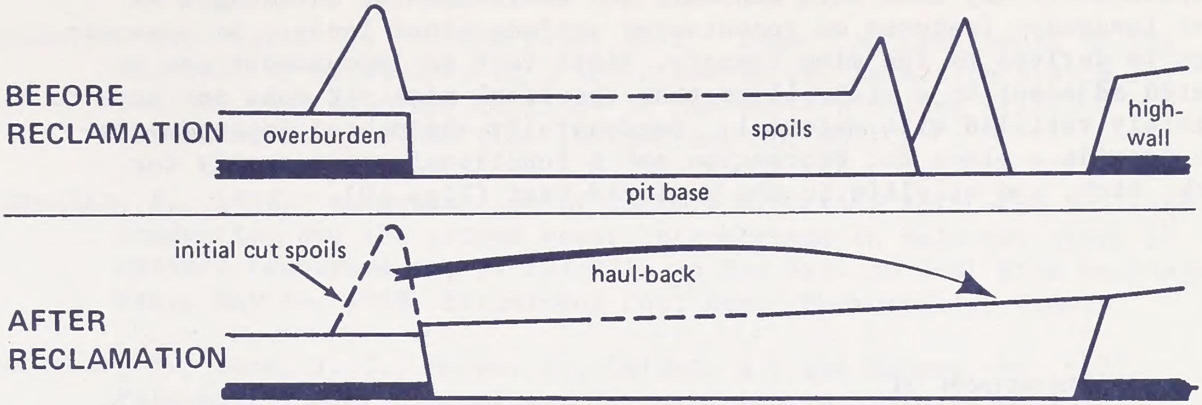

Figure 17. Schematic of highwall reclamation with haul-back method.

Highwall Reduction

Instead of hauling back initial cut spoils, materials in the highwall vicinity are graded to partially fill the final cut (Fig. 18). Concave slopes with granulations run into the partially filled final cut zone. The disadvantage of this method is that additional areas of land are disturbed atop the highwall as the highwall is reduced. This reclamation approach is costly, but not nearly as expensive as the haul-back method.

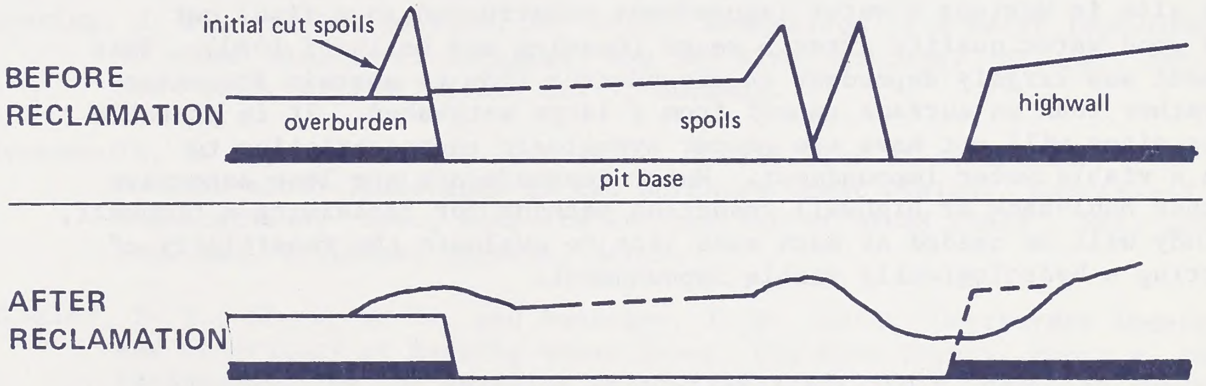

Figure 18. Schematic of highwall reclamation with highwall reduction method.

Water Impoundment

Water impoundments may have both economic and environmental advantages as permanent landscape features on recontoured surface-mined lands. An economic advantage is derived by the mine company, since such an impoundment can be constructed adjacent to a highwall so that the final mine pit does not have to be completely refilled with material. Successfully engineered impoundments can also provide a place for recreation and a functional water supply for livestock, fish, and wildlife in the semiarid West (Fig. 19).

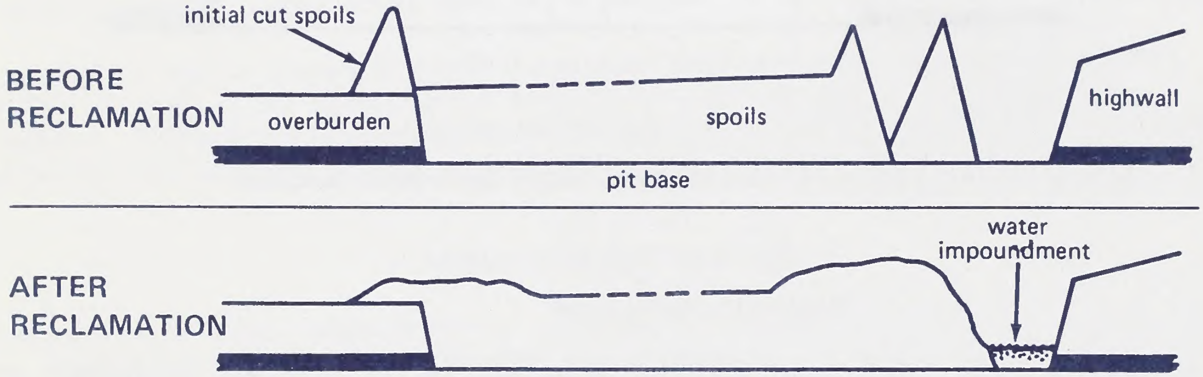

Figure 19. Schematic of highwall reclamation by implementing water impoundment.

There is concern that such impoundments may not be hydrologically viable. At one mine site in Montana a water impoundment constructed in a final cut retained good water quality after 5 years (Goering and Dollhopf 1980). This impoundment was largely dependent on groundwater flow to sustain its water level, rather than on surface runoff from a large watershed. It is probable some mine sites will not have the proper hydrologic characteristics to maintain a viable water impoundment. Water impoundments are less expensive than either haul-back or highwall reduction methods for reclaiming a highwall, but a study will be needed at each mine site to evaluate the feasibility of constructing a hydrologically viable impoundment.

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HYDROLOGIC PRINCIPLES AND MODELS RELATED TO SURFACE MINING

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THE HYDROLOGIC SYSTEM

Recognition that surface and subsurface waters are interdependent components of the hydrologic system dates back to the latter part of the 17th century. Prior to that time, the earth was thought to be practically impenetrable by rain water. The prevailing theory, articulated by many of the most prominent thinkers of the time, held that ocean water migrated inland through subsurface caverns and was eventually returned to the surface through springs. Elaborate corollary theories were advanced to explain how springs could exist at elevations above sea level and how the sea water was purified.

Today a great deal of mystique and misinformation remains about ground water in general and the interaction between surface and ground water in particular. It was less than 10 years ago that the interdependence of stream flow and alluvial ground water use was acknowledged in Colorado water law, for example. However, the Surface Mining Control and Reclamation Act of 1977 and the associated Permanent Regulatory Program implicitly recognize the interdependence of component subsystems when they speak in terms of the "hydrologic balance" and "hydrologic function."

It is particularly useful in mining-related hydrology to view surface and subsurface waters as components of a single system. In fact it is convenient to further subdivide the hydrologic system into surface water, soil water, and ground water subsystems. The interdependence of the subsystems is given full consideration by identifying the linkages between the subsystem. (See Fig. 1).

The first step in planning a hydrologic study for a particular situation is to identify the subsystems that are to be considered. Further subdivision may be convenient, particularly with respect to ground water; for example, a separate subsystem may be designated for each bedrock and alluvial aquifer. It is also important at this stage to establish the boundaries of each subsystem; they can be natural boundaries such as watershed divides, outcrops, etc., but this need not be the case. In many cases, the overall study area boundary will be an arbitrarily established perimeter around the permit area. The boundaries for each subsystem need not coincide. These brief statements concerning identifying the subsystems and establishing the subsystem boundaries are a tremendous oversimplification. Substantial geologic and hydrologic data are required. Revision of boundaries and subdivisions is usually required as the study progresses.

The linkages between subsystems shown in Figure 1 are generalized and must be refined and tailored to each individual study. At the planning stage, all the linkages may not be known. It is a major purpose of the hydrologic study to determine which linkages exist and to quantify them. Estimation of the impact on the system resulting from disruption of one or more linkages or disturbance of a subsystem then becomes possible. Mining often creates linkages that did not exist prior to mining. For example, groundwater inflow to the mining pit may be pumped and discharged to a stream. Also, disruption of the natural sequence of geologic strata may result in the opportunity for deep percolation from the soil-water susbsystem to enter aquifers that were previously isolated. Therefore, it is important to anticipate which existing linkages and

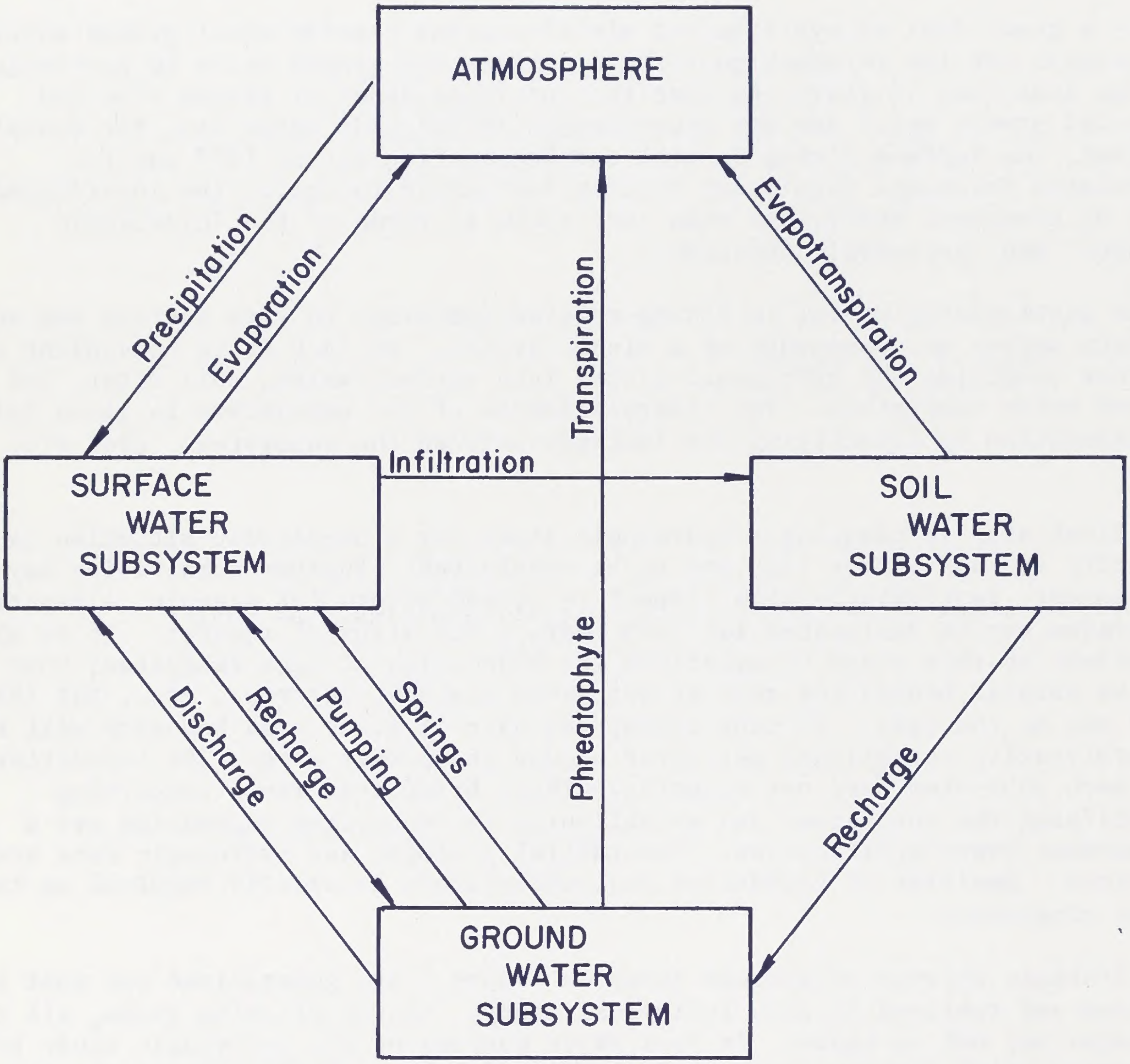


Figure 1. Linkages among the subsystems of the hydrologic cycle.

subsystems will be potentially affected and which new ones will be established so that the data required to quantify each one can be collected.

The data required for establishing the hydrologic balance become immediately apparent if explicit equations for the water balance in each subsystem are written out. This also assists in making conscious decisions concerning the methodology to be used to quantify the various linkages and subsystems. Individual terms to be included in the inputs and outputs from each subsystem are site specific and there is little to be gained by presenting generalized versions here. Examples of the use of water balance equations are included elsewhere in this paper.

The above discussion has emphasized the quantity of water that is stored and transferred within the hydrologic system. Equally important is the quality of these waters. Understanding the water quality in each component subsystem is even more difficult because of the many factors that influence water chemistry. Certainly knowledge of the quantities of water stored and transferred within the system is a prerequisite to understanding the water quality. The complex processes of chemical reaction, cation exchange, and adsorption that ultimately control the water quality are so difficult to quantify in most instances, that assessment of water quality impact is often reduced to simple mixing calculations. Further discussion of selected water quality considerations is contained in subsequent sections.

GROUND WATER SUBSYSTEM

Federal and State regulations require collecting baseline data prior to initiating mining, often referred to as premining monitoring; it is expected to cover at least 12 months prior to initiating mining. As suggested by the foregoing discussion, the premining study must be more than a monitoring program. It is important that the baseline data be collected in anticipation of using it in specific ways to establish a quantitative understanding of the hydrology and to estimate the changes that will result from mining. In this section relevant fundamentals of ground-water flow, data collection and models are discussed.

Fundamental Concepts

Ground water is water that occurs at pressures greater than or equal to atmospheric pressure in a variety of subsurface openings including interstitial voids, fractures, joints, and solution cavities. The bodies of geologic materials occupied by ground water are called aquifers; they are divided into two major types: unconfined and confined. An unconfined aquifer is one in which a water table exists. A water table is the surface formed by the locus of points at which the ground water is at atmospheric pressure (Todd 1959, McWhorter and Sunada 1977, DeWeist 1965, Freese and Cherry 1979). Water-filled alluvium and colluvium associated with streams are prominent examples of such aquifers. Specific examples are the unconfined, alluvial aquifers along Trout Creek in northwestern Colorado and along the Tongue River in Montana (McWhorter et al. 1979, Van Voast 1975, Woessner et al. 1979). Also, unconfined aquifers are often formed in terrace deposits by vertical recharge from precipitation or irrigation. Typically unconfined aquifers occur near the ground surface and are likely to be in hydraulic communication with surface water. Often, unconfined aquifers are of relatively small areal extent but are of particular importance as local water supplies for irrigation, domestic, and livestock use.

In contrast, confined aquifers usually occur in "bedrock" geologic strata and can be characterized as being pressured. The situation is not unlike water existing under pressure in a pipe. The confining beds that permit the existence of elevated pressures in the aquifer are called aquitards or aquicludes, the former being a stratum that greatly restricts ground-water flow and the latter being a material that precludes ground-water flow. An important example of a confined aquifer in Wyoming and Montana is the Madison Limestone. Confined aquifers are sometimes very extensive, underlying hundreds of square miles of land surface and are of regional importance. In other cases confined aquifers are local and play a much less significant role in the regional hydrology.

The widespread use of the word aquifer notwithstanding, the term remains only ambiguously defined as a body of geologic material that is capable of transmitting ground water of sufficient quantity and quality to meet a specific need to wells or springs. Thus, a water-bearing stratum that will sustain a yield of 1 gallon per minute (gpm) to a well might be considered an aquifer by one seeking to supply livestock water, but not by the irrigator who requires a yield of several hundred gpm. It is incumbent upon the hydrologist conducting ground-water investigations prior to mining to identify water-bearing intervals that could potentially be affected by the planned mine. It is also necessary to determine the significance of each water-bearing zone relative to current and potential water use practices in the study area. An inventory of wells, springs, stream flows, land use, and water rights in relation to the identified water-bearing intervals is helpful in this regard.

It is not necessary that a particular geologic stratum or interval be categorized throughout as confined or unconfined. In fact, the usual case is that ground water is confined in some areas and unconfined in others. Figure 2 is a cross section depicting a portion of the Twentymile Sandstone in Colorado and shows one circumstance in which this may occur. Incision of a confined aquifer by a mining pit causes the aquifer to become unconfined near the pit, even though the confined conditions may persist at points remote from the pit.

Aquifer Storage

Predicting the impact of mining on the ground-water subsystem depends upon knowledge of how aquifers respond to imposed stresses such as pumping, change in recharge, or incision by a pit. The most common manifestation of aquifer response is a change in water level in one or more wells. The water level in a well is a measure of the piezometric head of the water in the aquifer if the well has been properly completed. The piezometric (also called potentiometric) head in the ground water at a point is the sum of the pressure head and elevation head

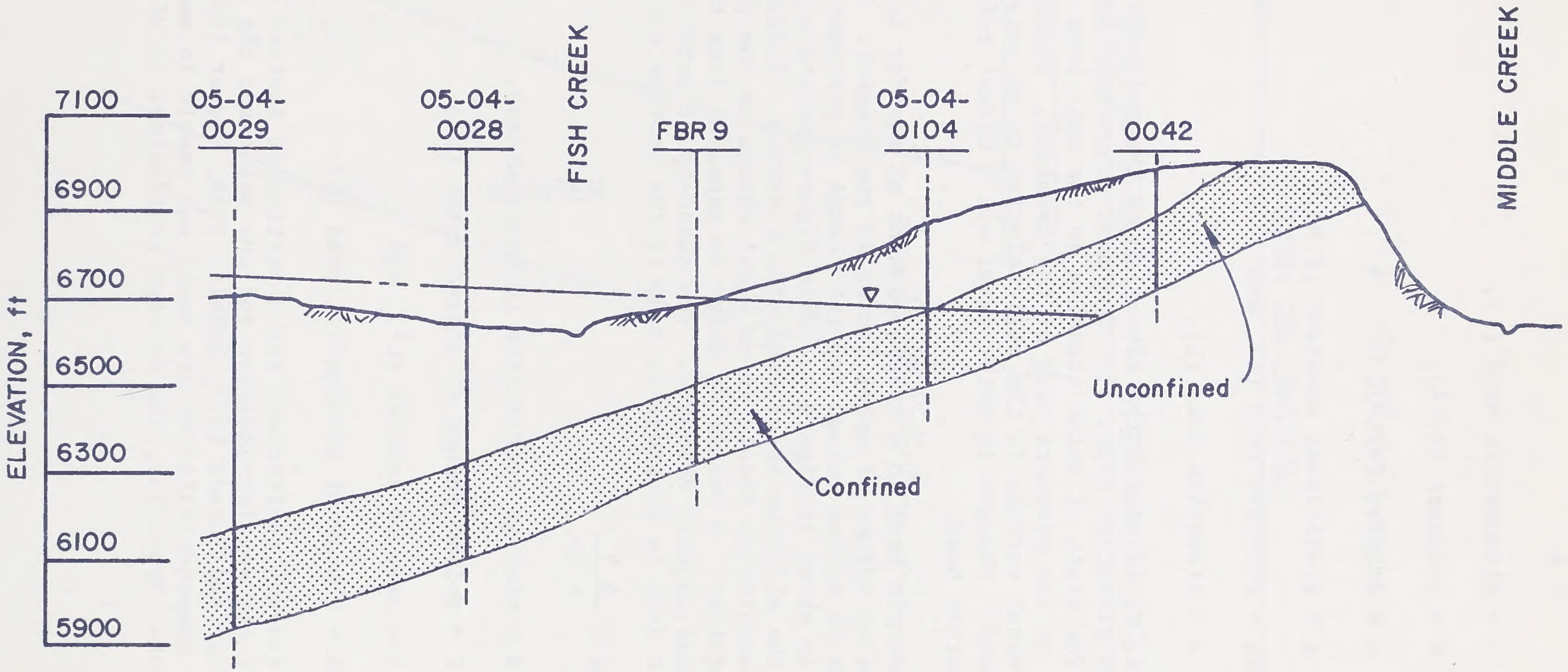


Figure 2. A geologic stratum with both confined and unconfined zones.

$$h = \frac{P}{\rho\ g} + z \qquad (1)$$

where h = piezometric head (L),

P = pressure (F/L^2),

ρ = density (M/L^3),

g = gravitional constant (F/M),

$P/\rho g$ = pressure head (L), and

z = elevation head (L).

The elevation head, z, is simply the elevation of the point in question above an arbitrary datum elevation (Fig. 3). The most convenient datum is usually mean sea level. The depth of water standing in the well bore above the terminus is equal to the pressure head at the terminus. Therefore, the elevation of the water surface in the well relative to an established datum is the piezometric head. Changes in water level are a direct reflection of changes in piezometric head.

A change in piezometric head in a volume element of aquifer is always associated with a change of volume of water stored in the element. The relationship between the change in stored volume and the change in piezometric head for a confined aquifer is shown in Figure 4. This figure depicts a confined aquifer that subcrops in the alluvium associated with a stream. A drop in stream stage by Δh will eventually result in an equal change in the piezometric head in the confined aquifer. A volume of water is expelled from the aquifer as the piezometric head adjusts downward. The quantity of water expelled per unit area per unit drop in piezometric head is the storage coefficient

$$S = \frac{\Delta\ V}{A\ \Delta h}, \qquad (2)$$

where S = storage coefficient (dimensionless),

ΔV = volume change of stored water (L^3),

A = area of aquifer (L^2), and

Δh = change of piezometric head (L).

The value of the storage coefficient for a particular aquifer depends upon the compressibility of the aquifer skeleton and the water and the aquifer thickness (McWhorter and Sunada 1977, DeWeist 1966, Cooper 1966). Both aquifer and water compressibilities are small and result in small values for storage coefficient. Typically, the storage coefficient is within the range of 10^{-5} to 10^{-3}.

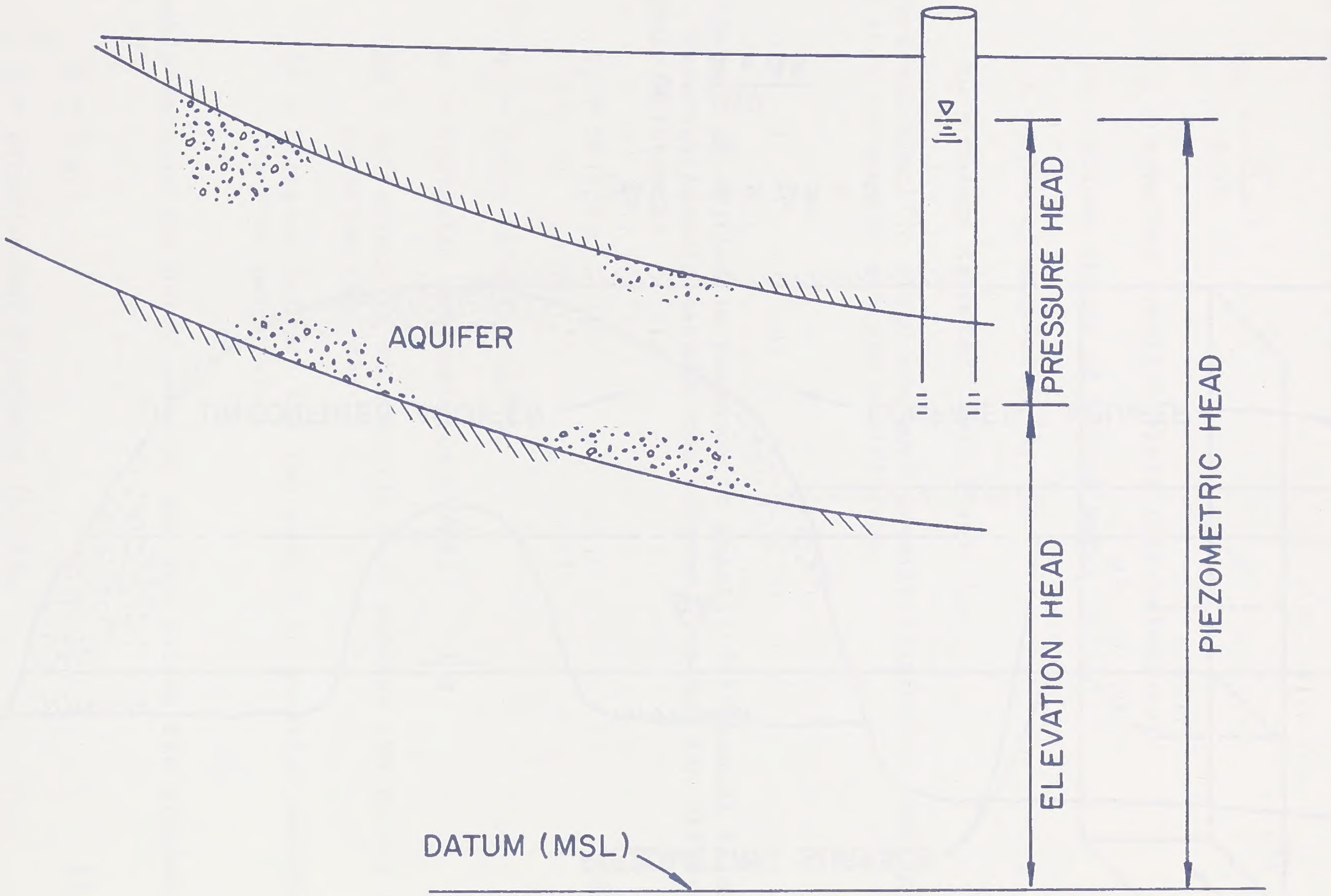
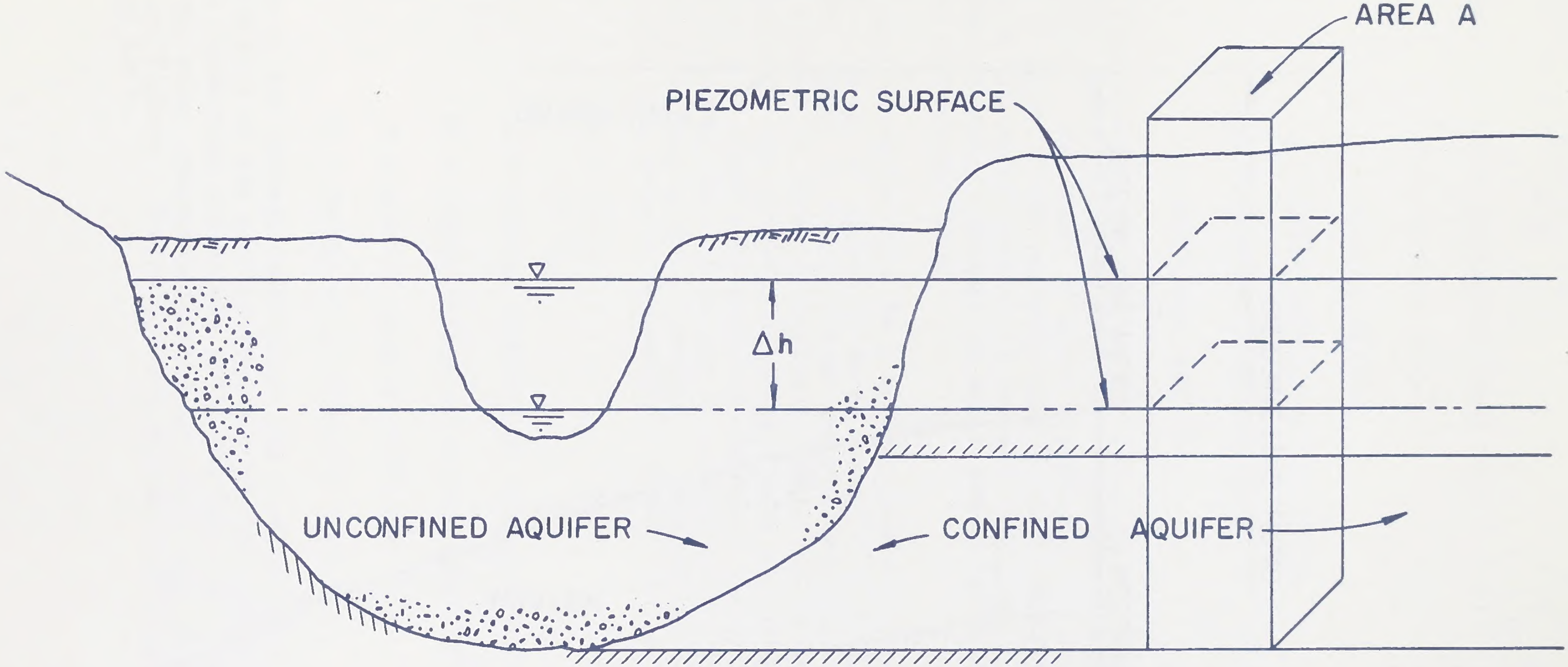


Figure 3. Water level elevation in a piezometer indicates the piezometric head.



$$\Delta V = A \times \Delta h \times S$$

or

$$S = \frac{\Delta V}{A \times \Delta h}$$

Figure 4. The relation between a change in head and a change in storage for a confined aquifer.

An analogous coefficient is used to characterize the storage capacity of unconfined aquifers (Fig. 5). In contrast to the confined aquifer, the volume of water expelled from the unconfined aquifer upon a change in piezometric head is controlled by physical drainage of the pores as the water table falls. The quantity of water expelled per unit area per unit drop in piezometric head is called the apparent specific yield.

$$S_{ya} = \frac{\Delta V}{A\,\Delta h}, \tag{3}$$

where S_{ya} = apparent specific yield (dimensionless),

ΔV = volume change of stored water (L^3),

A = area of aquifer (L^2), and

Δh = change in water table level (L).

Values for apparent specific yield are much greater (typically ranging from 0.05 to 0.3) than values for storage coefficient.

Darcy's Law

Water flows through an aquifer in response to spatial differences in piezometric head. The relationship between the rate of flow and the difference in head is commonly written as

$$q_\ell = -K \frac{\Delta h}{\Delta \ell}, \tag{4}$$

where q_ℓ = Darcy velocity (L/T),

K = hydraulic conductivity (L/T),

Δh = difference in piezometric head between two points in question (L), and

$\Delta \ell$ = distance between the two points in question measured along the flow path (L).

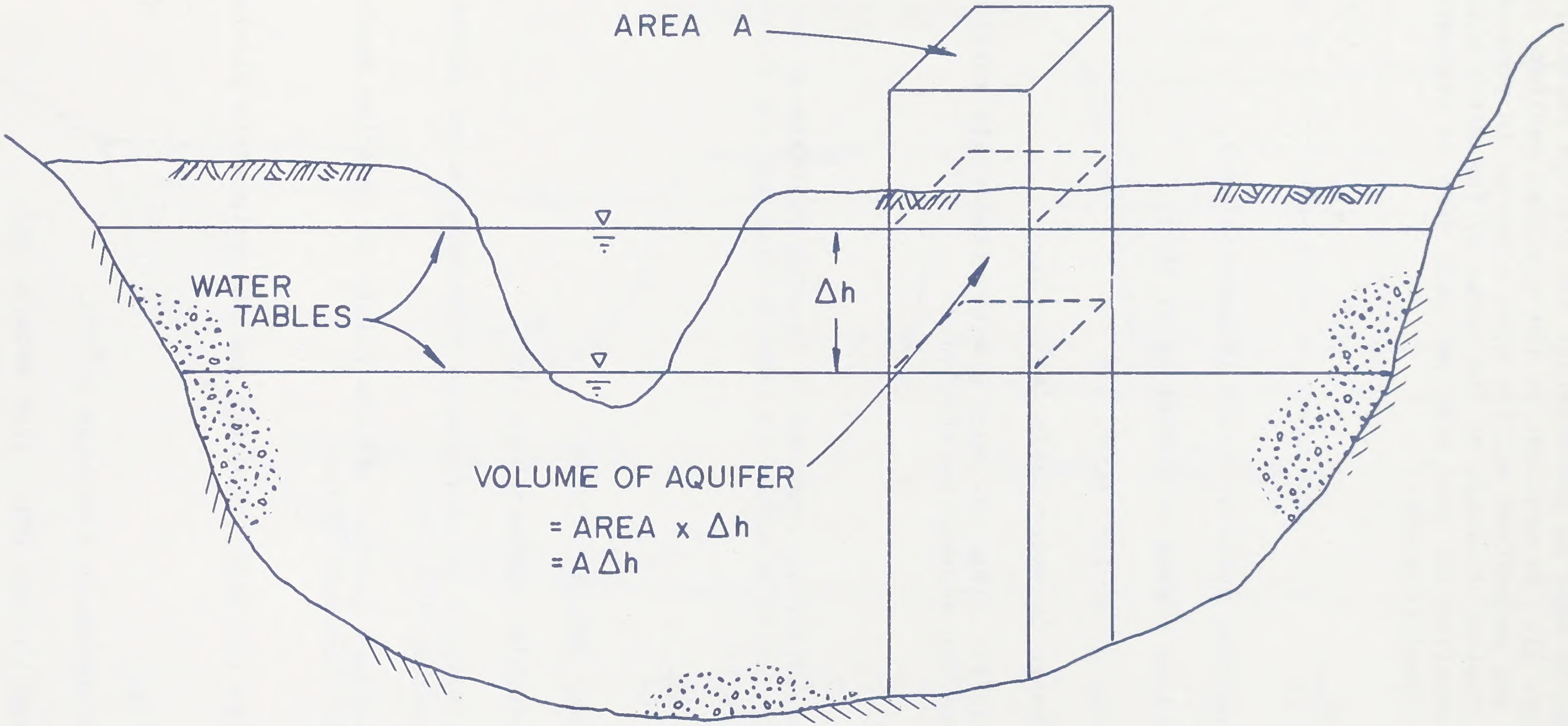
The relationship between the Darcy velocity and the volumetric discharge of ground water is

$$Q = A\,q_\ell, \tag{5}$$

where Q = ground-water discharge (L^3/T),

A = area through which flow occurs, and

q_ℓ = component of Darcy velocity directed normal to area A.



$$\text{VOLUME DRAINED} = S_{ya} \times A \times \Delta h$$

or

$$S_{ya} = \frac{\text{VOL. DRAINED}}{A \times \Delta h}$$

Figure 5. The relation between a change in head and a change in storage for an unconfined aquifer.

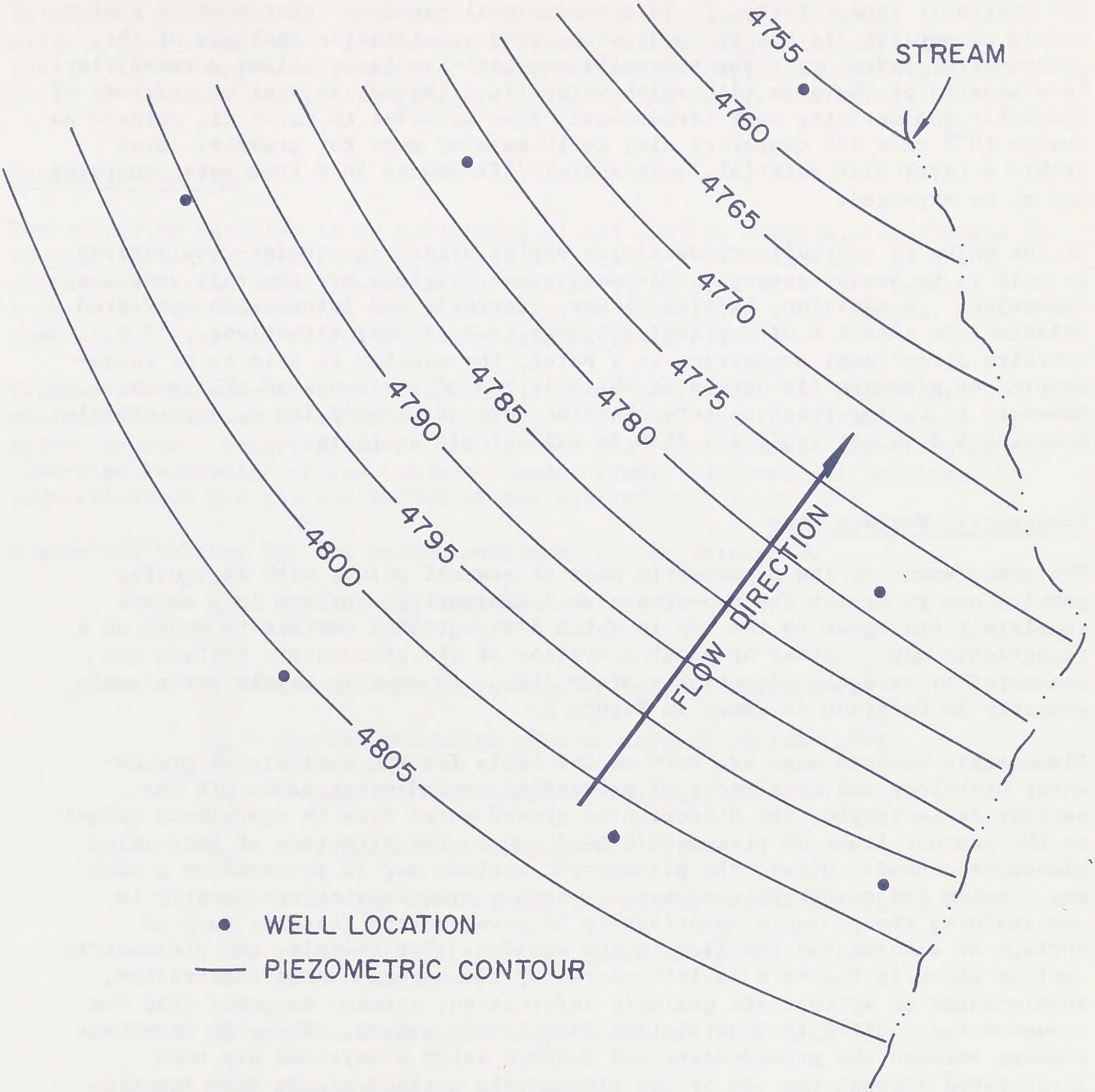


Figure 6. A piezometric surface map indicates the direction of flow.

In this form it is apparent that q_ℓ is more correctly viewed as a component of volume flux rather than a velocity. The area, A, through which the discharge occurs is a bulk area that includes both solid and pore space.

The hydraulic conductivity, K, is a fundamental parameter that must be evaluated to accomplish all but the most elementary quantitative analysis of the ground-water hydrology. The hydraulic conductivity (also called permeability) is a measure of the ease with which water flows through an aquifer. Values of hydraulic conductivity vary tremendously from material to material, perhaps as low as 10^{-9} cm/s for compacted clay to 10 cm/s or more for gravels. Even within a particular material, substantial differences in K from point to point are to be expected.

If the value of hydraulic conductivity varies within an aquifer, the aquifer is said to be nonhomogeneous. Nonhomogeneous aquifers are the rule, not the exception. In addition, bedding planes, fractures and joints with preferred orientations impart a directional property to K in many situations. If K exhibits directional properties at a point, the aquifer is said to be anisotropic, an adequate discussion of which is beyond the scope of this paper. However, it is important to note that the form of Darcy's law as expressed in Equation 4 does not apply for flow in anisotropic aquifers.

Piezometric Surface Maps

The measurement of the piezometric head at several points with an aquifer permits one to depict the two-dimensional piezometric surface in a manner completely analogous to the way in which a topographic surface is shown on a topographic map. Points of equal elevation of the piezometric surface are connected by an equal elevation contour line. An example result for a coal property in Colorado is shown in Figure 6.

Piezometric surface maps are very useful tools for the analysis of ground-water hydrology and as a means of presenting ground-water data. If the aquifer is isotropic, the direction of ground-water flow is everywhere normal to the contour lines of piezometric head and in the direction of decreasing piezometric head. Often, the piezometric surface map is prepared on a base map showing the topographic contours. Such a procedure asists greatly in ascertaining the probable relationship between surface features such as springs or streams and the flow in the aquifer. For example, the piezometric surface shown in Figure 6 in intersected by the stream. This observation, supplemented by appropriate geologic information, strongy suggests that the ground-water aquifer is contributing flow to the stream. Thus, an important linkage between the ground-water and surface water subsystems has been established through the use of the piezometric surface map in this example.

Equations of Ground Water Flow

The equations upon which quantitative models of ground-water motion are based are formed by combining the concepts of aquifer storage and Darcy's law with the principle of conservation of matter. This requires that a control volume be established to which the conservation principle is to be applied. The control volume selected for use can be the entire subsystem under consideration. This selection leads to an expression which will be termed "the macroflow equation." At the other extreme is the application of material balance to infinitesimal control volumes, in which case, the result is the differential equation of ground-water flow. Between these two extremes is the possibility of expressing material conservation on individual members of an array of elements which, in aggregate, make up the entire susbsystem.

Macroflow Equation

The macroflow equation is an accounting of all inputs, outputs, and changes of storage within the subsystem under study. A good deal of insight into the usefulness of the macroflow equation is lost if written in a very general form. For this reason the macroflow equation is written for a special case that will adequately demonstrate the salient features.

Suppose the ground-water subsystem of interest is the one for which the piezometric surface is shown in Figure 6. Further, imagine an aribtrary permit boundary superimposed on the map and that this boundary constitutes the plan-view boundaries of the subsystem under study. In vertical section, the boundaries are the top and bottom of the aquifer.

A material balance for the entire subsystem can be written as

$$Q_o - Q_i + R - Q_p = AS\frac{\Delta h}{\Delta t}, \qquad (6)$$

where Q_o = average discharge rate of lateral outflow (L^3/T),

Q_i = average discharge rate of lateral inflow (L^3/T),

R = average rate of vertical recharge (L^3/T),

Q_p = average rate of pumpage (L^3/t),

A = plan-view area within the system boundaries (L^2),

S = storage coefficient or apparent specific yield (dimensionless),

Δh = spatial average change in piezometric head (L), and

Δt = time increment (T).

The quantities Q_o and Q_i are the ground-water outflow and inflow, respectively, across the lateral boundaries of the subsystem. Note that they are average values for the time increment t. The lateral inflow and outflow can be computed from

$$Q = A_s K \frac{\Delta h}{\Delta \ell} \tag{7}$$

where A_s is the section area through which flow occurs, K is the hydraulic conductivity of the aquifer at the boundary and $\Delta h/\Delta \ell$ is the component of piezometric gradient normal to the area A_s determined from the piezometric surface map. Usually, Equation 7 is applied over convenient increments of the boundary and the results summed for all such increments. This permits one to take into account complex geometries and variable K.

It will be noted that the change in storage within the subsystem is equated to the sum of various inputs and outputs evaluated on the boundaries. Thus, no knowledge of hydraulic conductivity within the interior of the subsystem is required. On the other hand, the value of Δh over the time period Δt used on the right of Equation 6 must be appropriately averaged over the entire area of subsystem. This may be difficult to accomplish, especially if water levels are rising in one portion of the system and falling in another.

Rarely does one attempt to evaluate each term in Equation 6 from independent measurements, although it is desirable to do so when feasible. The recharge term, R, is particularly difficult to estimate from independent measurements. However, the recharge can be estimated directly from Equation 6 by evaluating all other terms. The result is a lump value for R and no information concerning the spatial distribution is obtained. Water level measurements within the study area and geologic data may permit the determination of recharge zones.

Differential Flow Equations

Selection of a differential volume element of aquifer for application of mass conservation leads to a partial differential equation (McWhorter and Sunada 1977, Freeze and Cherry 1979). A general form, applicable for three-dimensional flow in a nonhomogeneous, anisotropic aquifer, can be written. Less general forms are obtained by making selected assumptions concerning the variation of hydraulic properties and the dimensionality of the flow. A rather general form that is commonly used as a basis for modeling ground-water flow in relation to mining is:

$$\frac{\partial}{\partial x}\left(K_x b \frac{\partial h}{\partial x}\right) + \frac{\partial}{\partial y}\left(K_y b \frac{\partial h}{\partial y}\right) + W = S \frac{\partial h}{\partial t}, \tag{8}$$

where K_x = hydraulic conductivity in x-direction (L/T),

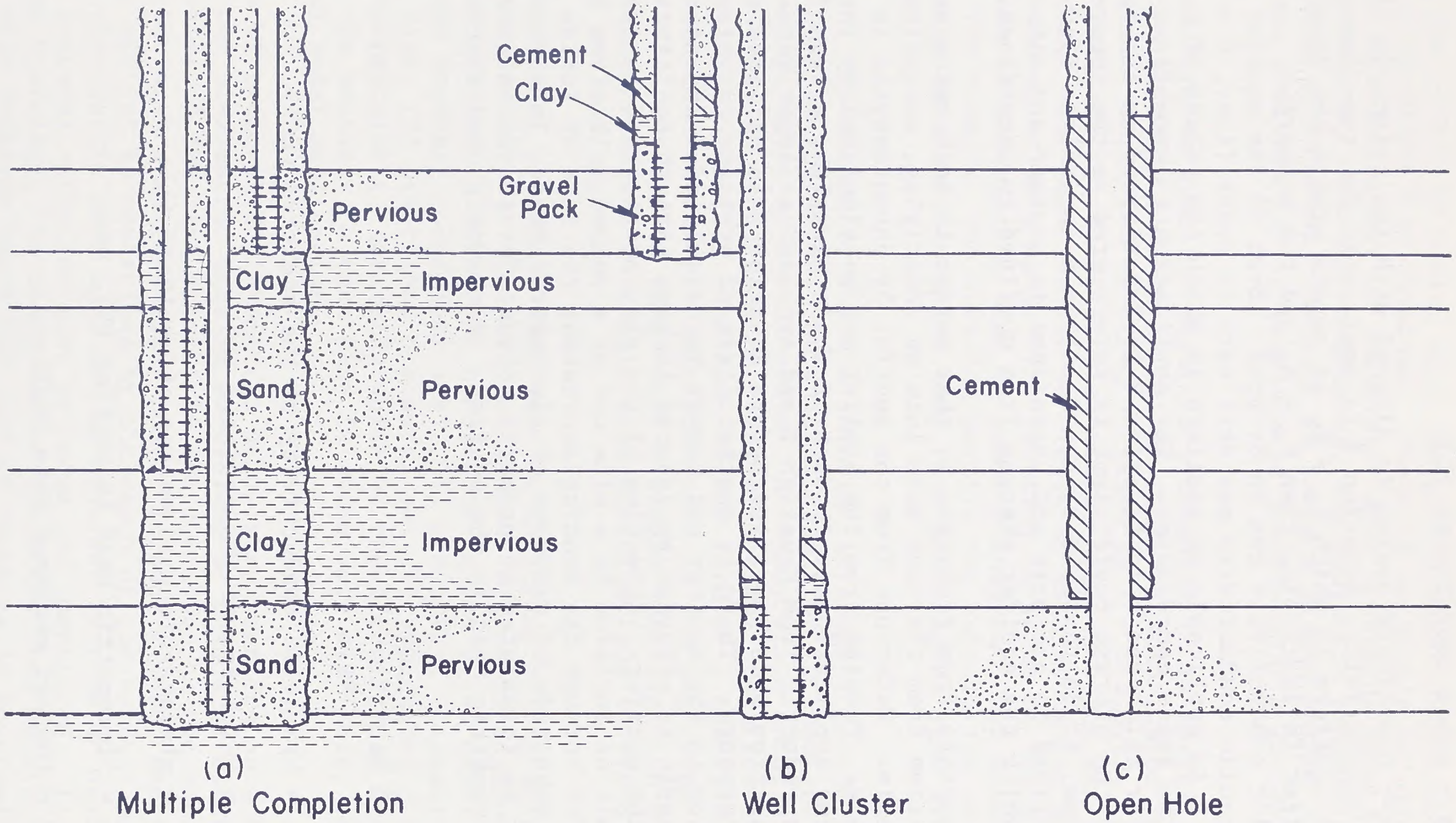
K_y = hydraulic conductivity in y-direction (L/T),

b = aquifer thickness (L),

h = piezometric head (L),

W = recharge rate (volume per unit area per unit time, L/T),

S = storage coefficient (dimensionless),



(a) Multiple Completion

(b) Well Cluster

(c) Open Hole

Figure 7. Examples of well completion methods.

t = time (T), and

x,y = space coordinates (L).

Provided that the x-y coordinate system is aligned with the principle directions of hydraulic conductivity, Equation 8 is applicable for two-dimensional flow in anisotropic aquifers in which $K_x \neq K_y$ at points within the flow field. If the aquifer is isotropic, then $K_x = K_y$ and the subscript attached to hydraulic conductivity can be dropped. Even if the aquifer is isotropic, the hydraulic conductivity may stil vary in space (i.e., $K = K(x,y)$). Equation 8 is applicable to aquifers in which the values of K, b, and S depend upon the space coordinates. For application to unconfined aquifers, the aquifer thickness b in Equation 8 is interpreted as the saturated thickness and the storage coefficient is interpreted as the apparent specific yield. Thus, it is possible to use Equation 8 to analyze flow in an aquifer that is confined in one part and unconfined in another and also to model the case in which the aquifer changes from confined to unconfined.

Equation 8 is appropriate from recharge, W, that varies in both space and time. Deep percolation from the root zone into an underlying, unconfined aquifer is one example. Water use from the aquifer by phreatophytes is an example of negative W. Pumping from the aquifer can be simulated by the recharge term in some applications. In each of these examples, values for W are determined independently from Equation 8 and are used as input data. In other words, the function W is specified before Equation 8 is utilized to determine aquifer response. There is another class of problems in which W depends upon the flow in the aquifer and cannot be calculated independently. The most common example is afforded by induced leakage through aquitards that overly or underly the aquifer. Reduction of the piezometric head in the aquifer as the result of incision by a mine cut or a pumped well often induces inflow to the aquifer through the bonding aquitards; the rate of inflow being dependent upon the magnitude of drawdown of piezometric head. In such cases, the recharge W must be formulated to properly account for the dependence of recharge on the piezometric head in the aquifer. A commonly used expression is

$$W = K_a \frac{(h_o - h)}{b_a}, \qquad (9)$$

where K_a = hydraulic conductivity of the aquitard (L/T),

b_a = thickness of the aquitard (L),

h_o = piezometric head on top of aquitard (L),

h = piezometric head in aquifer (L), and

W = induced recharge rate (L/T).

Requisite Data

Predicting the effect of mining upon the ground water subsystem requires that solutions of Equation 8 be obtained. There is no single solution; rather, there is an infinite number of solutions, each depending upon the geometry, initial conditions, boundary conditions, and hydraulic properties pertaining to the problem of interest. Neither is there a single method by which solutions are derived. It is possible to provide only a few salient features here.

Before proceeding to specific solution procedures it is useful to review what is meant by a solution and how it can be used. A solution of Equation 8, or any appropriate simplified version, is given by $h = h(x,y,t)$. In other words, a solution consists of values of piezometric head in space and time within the solution space. The solution can be displayed as piezometric surface maps, tables of values, or as graphs. The solution in terms of the space and time distributions of piezometric head is used to compute other aspects of interest. For example, the solution permits the calculation of inflow to the pit, discharge to a surface water body, and patterns of flow within the aquifer.

Regardless of the method by which a solution is sought, boundary and initial conditions must be specified. An initial condition is required for all solutions except those of steady state. A steady state solution is one in which the piezometric head does not vary with time. Solution for any unsteady problem requires an initial condition in the form of a specified distribution of piezometric head within the solution space at the beginning of the model period. Initial conditions range from a simple specification of uniform, constant piezometric head to complicated distributions inferred from measured piezometric surface maps.

Boundary conditions are those that must be satisfied by the solution at all points on the boundary of the solution space. Different segments of the boundary are subject to different conditions in the usual case. The most commonly used boundary conditions are: (1) prescribed piezometric head, (2) prescribed flux, (3) prescribed pressure, and (4) prescribed gradient. It is up to the hydrologist to determine which of these conditions exist on each segment of the boundary; a task that is often very difficult, yet critical to a successful model application.

A condition of prescribed piezometric head is appropriate on a boundary segment if the piezometric head is controlled by phenomena external to the solution space. A familiar example is the condition on the aquifer surface in direct contact with a surface water body. In such a case, the piezometric head on the aquifer is controlled by the depth of the surface water. The prescribed piezometric head need not be constant in time or space, but any spatial or temporal variation must be known and quantified. In mining-related ground-water hydrology, the condition of specified flux usually occurs in connection with recharge where the rate of recharge is governed by conditions external to the ground-water subsystem. Zero flux across impervious boundaries is an important special case of a flux condition. Incision of an aquifer by a mine pit creates a condition of prescribed pressure on the exposed face, which is often referred to as a seepage face. A prescribed gradient is a condition sometimes used in the modeling of unconfined flow in which the slope of the water table is controlled, but the saturated thickness is not. In confined flow, prescribing the gradient on portions of the boundary is tantamount to prescribing the flux.

In addition to the initial and boundary conditions discussed above, the hydraulic properties of the aquifer must be known. Hydraulic properties refer to the hydraulic conductivities and storage coefficient that appear in Equation 8. Rarely are these properties constant over large areas and successful modeling often requires that their variation in space be known and accounted for in the calculations. Methods by which the hydraulic properties can be obtained are presented in a subsequent section.

Solution Methods

Procedures whereby solutions of Equation 8 (or appropriate simplified forms) may be obtained can be grouped into three broad categories: (1) analytical, (2) numerical, and (3) analog methods. Analog methods have fallen into relative disuse with the tremendous growth of digital computing capabilities and only analytical and numerical methods are given further consideration here.

Analytical methods refer to the classical mathematical procedures whereby closed form formulas for the solution are obtained. Examples are direct integration, separation of variables, and Laplace transform techniques. Equation 8 must be substantially simplified before even the most powerful analytic techniques will yield a solution. Simplifying Equation 8 by suitable restrictions on hydraulic property variation, and additional constraints relative to the geometry, boundary, and initial conditions that can be handled, impose corresponding restrictions on the generality and usefulness of the obtained solution. Nevertheless, analytic solutions find widespread use in mining hydrology, particularly in respect to local problems such as pit inflow estimation, dewatering considerations, and determining hydraulic properties.

With a very few exceptions, analytic solutions to Equation 8 are derived by assuming that the aquifer is homogeneous and isotropic with respect to hydraulic conductivity and storage coefficient. Further, the aquifer thickness b is taken as constant so the Equation 8 becomes

$$\frac{\partial^2 h}{\partial x^2} + \frac{\partial^2 h}{\partial y^2} + \frac{W}{T} = \frac{S}{T}\frac{\partial h}{\partial t}, \qquad (10)$$

where T = Kb = transmissivity (L^2/T). The list of analytic solutions of Equation 10 that find use in mining hydrology is far too long to provide here. It was deemed more appropriate to demonstrate selected analytic solutions to specific problems; these examples are presented in a subsequent section.

Numerical methods of solution refer to computer-assisted integrations of the partial differential equation. The two most familiar examples are the finite difference and finite element method (Remson et al. 1971). The finite difference method consists of approximating the point derivatives that appear in Equation 8 by finite differences obtained from Taylor series expansions, accomplished through the use of a grid system superimposed upon the solution domain. The partial derivatives at the mesh point are replaced by finite difference approximations to yeild a system of algebraic equations amenable to solution by digital computer. This is tantamount to applying the mass conservation equation as expressed in Equations 6 and 7 to each individual grid.

Depending upon how one formulates the finite difference approximation to the time derivative, an explicit or implicit set of algebraic equations is obtained. In either case, the system of equations is solved at discrete time intervals (i.e., at the end of successive time steps). The solution is manifest as values of piezometric head at the center of each grid at the end of each time step. Thus, the solution is discrete in both time and space, in contrast to the continuous solution provided by analytic solutions. The explicit formulation, which is somewhat simpler to understand and to program for computation, is subject to a very restrictive stability criterion. The disadvantage of computational efficiency resulting from the stability criterion usually outweighs the limited advantages of the explicit formulation. The implicit finite difference formulation is unconditionally stable and permits a much greater latitude in the selection of grid size and time step to meet the needs of a particular problem.

The classical finite element method is based upon minimizing a functional derived from the differential equation using the variational calculus. The method also encompasses the technique in which one seeks to minmize the error or residual that exists between the exact and an approximating function. The theoretical foundations of the finite element method are somewhat more involved than for the finite difference methods and will not be given here. Suffice it to say that the finite element method also results in a system of algebraic equations, the solution of which gives the piezometic head at discrete nodal points formed by a usually triangular mesh overlying the solution space. The solution is advanced in time by discrete steps just as is the finite difference solution. Advantages of the finite element method are the relative convenience of handling boundary conditions, of aproximating curvilinear boundaries by the triangular elements, and of tailoring the mesh to accommodate areas in which the gradient is large or small.

It should be understood that the finite difference and finite element method are techniques whereby approximate solutions of the governing equations are developed. They do not provide ready insight into the general relationship among the solution, hydraulic parameters, and boundary conditions as do analytical solutions. Any important limiting solutions that might be very general and widely applicable will usually be masked because the solution format is simply a table of values. It has been said that "analytical solutions speak, while numerical solutions are mute." However, the overriding advantage of numerical methods is their adaptability to problems in which the advantage may be largely compromised by inadequate data and/or lack of knowledge relative to the system geometry and boundary conditions. It is emphasized that no model compensates for lack of or the poor quality of requisite data.

Ground-Water Investigations

A review of the foregoing sections reveals a substantial list of ground-water data that must be acquired before mining impacts can be sucessfully predicted. Included in the list are identifying aquifers, the physical boundaries of each aquifer, the type of boundary conditon that prevails on each segment of the boundaries and the hydraulic properties of each aquifer. Determining the type of boundary condition on each boundary segment is equivalent to determining the linkages discussed previously. Consideration of the physical changes that will result from mining must be given to assure that specific data requirements relative to these changes are accommodated.

With few exceptions, observation of ground-water and aquifer conditions is made by indirect means. Of central importance is a knowledge of the geology and its relationship to ground-water flow. Thus, all gelological and geophysical investigative techniques are relevant to ground-water investigations. The reverse of this statement is also true. It is the intent of this section to review several procedures that are commonly used to provide basic ground-water data.

Geology

Conventional surface geologic maps prepared from investigations of formation outcrops and other surface features are an important tool in the interpretation of the subsurface hydrology. Particularly important is the delineation of outcrops of potentially water-bearing strata in relation to potential areas of recharge or discharge (e.g., incision of strata by a stream, existence of springs in relation to surface geology). Location and description of faults, fractures, and joints are also of special importance. Conventional and infrared photography are very helpful in preparaing such maps.

One of the objectives of the hydrogeologic investigation is to identify those water-bearing strata that warrant further investigation and testing. Areal continuity and water-transmitting capacity are the major determinants of such strata and can be investigated by both surface and subsurface geophysical techniques. Among the several surface geophysical techniques that have been found useful are electrical resistivity surveys and seismic surveys. Electrical resistivity surveys are conducted by passing an electrical current into the ground through two current electrodes and measuring the potential at two potential electrodes. Both vertical and horizontal profiling can be accomplished to provide data on hydrostratigraphic changes and structure (Williams-Robinette and Assoc. 1980). Similar information is provided by seismic surveys that utilize the transmission of elastic waves created by a dropped weight or explosion. The reader is referred to Zohdy et al. (1974) for the details of these and other surface geophysical methods.

Subsurface geophysical methods refer to borehole logging. Stratigraphic data obtained by careful examination and logging of drill cutting can be greatly supplemented by data from geophysical logs. A summary of the various borehole logs and their uses are given in Table 1. Technical features of borehole logging are contained in various manuals published by manufacturers and in numerous technical papers (e.g., Baltosser and Lawrence 1970, Boyle and Saleem 1979, Croft 1971, Dyck et al. 1972, Guyod 1966, Jones and Buford 1951, Keys and McClary 1976, Pirson 1963, and Society of Petroleum Engineers 1971).

Coal properties are extensively drilled during exploration to determine the quantity and quality of the reserves. Additional drilling for hydrogeologic purposes can be minimized by coordinating the exploration and hydrologic investigations. Qualitative information relative to water-transmitting capacity of strata penetrated can be obtained by observing fluid returns during drilling. This is accomplished most effectively when the drilling fluid is air and becomes very difficult if water or mud is used as the drilling fluid. Even with air, it becomes increasingly difficult to determine which strata contribute water after the first water-bearing interval is encountered. Nevertheless, careful observation of drill cuttings, fluid returns, and probable intervals of water entry during exploration drilling will greatly assist subsequent hydrologic investigations. It is often advantageous to complete selected exploration boreholes with casings and well screen for later use in aquifer testing and hydrologic monitoring.

Well Location and Construction

The geologic data, together with available surface information (e.g., locations and types of streams, topography, and mine plan) can be used as a guide to locating test and monitoring wells. At least preliminary plans for the type and number of tests to be conducted are also required. As pointed out previously, a piezometric surface map is a fundamental tool in ground-water analysis and care should be taken to locate wells so that the preparation of such a map is facilitated. If there is more than one aquifer that requires detailed investigation, more than one piezometric map will be required. The same well bore can be used to provide piezometric surface data in multiple aquifers if the well is properly planned and completed.

In most cases preliminary information will delineate locations that are particularly critical for testing or monitoring. For example, the location of existing wells, springs or potential areas of recharge is especially important. It is usually desirable to locate monitoring wells at both up- and down-gradient locations relative to the mine. Full consideration of the mine plan in relation to streams, alluvial aquifers, potential faults, etc. should be given. It might be advisable to concentrate ground-water testing in the buffer strip between an alluvial aquifer and the mine, for example, when such a circumstance exists.

TABLE 1. STANDARD DOWNHOLE GEOPHYSICAL LOGGING METHODS.*

Method	Uses	Recommended conditions
Electric logging: Single electrode resistance	Determining depth and thickness of thin beds. Identification of rocks, provided general lithologic information is available. Correlation of geologic formations or beds. Determining casing depths.	Fluid-filled uncased hole. Fresh mud required. Hole diameter less than 8 to 10 inches.
Short normal (electrode spacing of 16 inches)	Picking tops of resistive beds. Determining resistivity of the invaded zone. Estimating porosity of formations (deeply invaded and thick interval). Correlation and identification of geologic formations provided general lithologic information is available.	Fluid-filled uncased hole. Ratio of mud resistivity to formation – water resistivity should be 0.2 to 4
Deep lateral (electrode spacing approximately 19 inches)	Determining true resistivity where mud invasion is relatively deep. Locating thin beds.	Fluid-filled uncased holes. Fresh mud. Formations (rock units) should be of thickness different than electrode spacing and should be free of thin limestone beds.
Limestone sonde (electrode spacing of 32 inches)	Detecting permeable zones and determining porosity in hard rock. Determining formation factor in sites.	Fluid-filled uncased hole. May be salty mud. Uniform hole size. Beds thicker than 5 ft.
Laterlog	Investigating true resistivity of thin beds. Used in hard formations drilled with very salty muds. Correlation of formations, especially in hard rock regions.	Fluid-filled uncased hole. Salty mud satisfactory. Mud invasion not too deep.
Neutron	Delineating formations and correlation in dry or in cased holes. Qualitative determination of shales, tight formations, and porous sections in cased wells. Determining porosity and water content of formations, especially those of low porosity. Distinguishing between water or oil-filled or gas-filled reservoirs. Combined with gamma-ray log for better determination of lithology (rock type) and correlation of formations. Indicates cased intervals. Logging in oil-based muds.	Fluid-filled or dry cased or uncased hole. Formations relatively free from shaly material. Diameter less than 6 inches for dry holes. Hole diameter similar throughout.
Density	Used as a porosity logging tool. Other uses include identification of minerals in evaporite deposits, detection of gas, determination of hydrocarbon density, evaluation of shaly sands and complex lithologies, and detecting grout.	Fluid-filled or dry uncased hole.
Induction logging	Determining true resistivity, particularly for thin beds (down to about 2 ft thick in wells drilled with comparatively fresh mud. Determining resistivity of formations in dry holes. Logging in oil- based muds. Defining lithology and bed boundaries in hard formations. Detection of water bearing beds.	Fluid-filled or dry uncased hole. Fluid should not be too salty.
Microlog	Determining permeable beds in hard or well consolidated formations. Detailing beds in moderately consolidated formations. Correlation in hard rock regions. Determining formation factor in sites in soft or moderately consolidated formations. Detailing very thin beds.	Fluid-filled uncased hole. Bit-size holes (caved portions of hole only logged if enlargements are not great).
Microlaterlog	Determining detailed resistivity of flushed formation at wall of hole when mudcake thickness is less than ⅜ inches in all formations. Determining formation factor and porosity. Correlation of very thin beds.	Fluid-filled uncased hole. Thin mudcake. Salty mud permitted.
Spontaneous potential	Helps delineate boundaries of formation and the nature of these formations. Determine values of formation-water resistivity. Qualitative indications of bed shaliness.	Fluid-filled uncased hole. Fresh mud.
Radiation logging: **Gamma ray**	Differentiating shale, clay, and marl from other formations. Correlation of formations. Measurement of inherent radioactivity in formations. Checking formation depths and thickness with reference to casing collars before perforating casing. For shale differentiation when holes contain very salty mud. Radioactive tracer studies. Logging dry or cased holes. Locating cemented or cased intervals. Logging in oil-based muds. Locating radioactive ores. In combination with electric logs for locating coal or lignite beds.	Fluid-filled or dry cased or uncased hole. Should have appreciable contrast in radioactivity between adjacent formations.

TABLE 1. (Continued).

Method	Uses	Recommended conditions
Sonic logging	Logging acoustic velocity for seismic interpretation. Correlation and identification of lithology. Reliable indication of porosity in moderate to hard formations, in soft formations of high porosity it is more responsive to the native rather than the quantity of fluids contained in pores.	Not affected materially by the type of fluid, hole size, or mud invasion.
Temperature logging	Locating approximate position of cement behind casing. Determining thermal gradients. Locating depth of lost circulation. Locating active gas flow. Used in checking depth and thickness of aquifers. Locating fissures and solution openings in open holes and leaks or perforated sections in cased holes. Reciprocal-gradient temperature log may be more useful in correlation work.	Cased or uncased hole. Can be used in emply hole if logged at very slow speed, but fluid preferred. Fluid should be undisturbed (no circulation) for 6 to 12 hours minimum before logging; possibly several days may be required to reach thermal equilibrium.
	Locating point of entry of different quality water through leaks or perforations in casing or opening in rock hole. Determining quality of fluid in hole for improved interpretation of electric logs. Determining fresh-water-salt-water interface.	Fluid required in cased or uncased hole. Temperature log required for quantitative information.
Fluid-velocity logging	Locating zones of water entry into hole. Determining relative quantities of water flow into or out of these zones. Determining direction of flow up or down in sections of hole. Locating leaks in casing. Determining approximate permeability of lithologic sections penetrated by hole or perforated section of casing.	Fluid-filled cased or uncased hole. Flange or packer units required in large diameter hole. Caliper log required for quantitative interpretation. Injection, pumping, flowing, or static surface conditions.
Casing-collar locator	Locating position of casing collars and shoes for depth control during perforating. Determining accurate depth reference for use with other types of logs.	Cased hole.
Cement bond logging	Used to assess the quality of the cement-to-using bond around a cemented casing.	Cased hole.
Caliper (section gage) survey	Determining hole or casing diameter. Indicates lithologic character of formations and coherency of rocks penetrated. Locating fractures, solution openings, and other activities. Correlation of formations. Selection of zone to set a packer. Used in quantitative interpretation of electric, temperature, and radiation logs. Used with fluid-velocity logs to determine quantities of flow. Determining diameters of underreamed sections for placement of gravel pack. Determining diameter of hole for use in computing volume of cement to seal annudar space. Evaluating the efficiency of explosive development of rock wells. Determining construction information on abandoned wells.	Fluid-filled or dry cased or uncased hole. Does not give information on beds behind casing in a cased hole.
Dipmeter survey	Determining dip angle and dip direction (from magnetic north) of a bedding plane in relation to the well axis. A comprehensive study of computed data from a dipmeter survey makes possible the identification of faults, unconformities, cross hedding, sand bars, reefs, channels, deformation around salt domes, and other structural anomalies.	Fluid-filled uncased hole. Directional survey (see below) required for determination of true dip and strike (generally obtained simultaneously with dipmeter curves).
Directional (inclinometer) survey	Locating points on a hole to determine deviation from the vertical. Determining true depth. Determining possible mechanical difficulty for casing installation or pump operation. Used in determining true dip and strike from dipmeter survey.	Fluid-filled or dry uncased hole.
Magnetic logging	Determining magnetic field intensity in borehole and magnetic susceptibility of rocks surrounding hole. Studying lithology and correlation, especially in igneous rocks.	Fluid-filled or dry uncased hole.

*After Barrett et al. 1980.

The construction and completion of wells to be used in the investigation must be properly accomplished if reliable data are to be obtained. It is not uncommon for multiple aquifer systems to exhibit different piezometric heads in each aquifer. A borehole that penetrates two or more strata with different piezometric heads provides a short circuit among the strata and an opportunity for waters from one aquifer to flow into another. Water level data from a borehole penetrating zones of different piezometric head are essentially useless for determining piezometric head. Water level data that can be reliably interpreted requires that multiple aquifers be isolated from each other in the well bore. A cluster of wells, each completed in different zones, or a single borehole within which the individual zones are isolated, are common installations. Schematic examples are shown in Figure 7.

Wells are usually used for purposes in addition to measuring the piezometric surface. Sampling for water-quality determinations and testing for estimating hydraulic properties are additional uses that impose certain requirements on construction and completion. Multiple zone completions, as shown in Figure 7 (a), are not appropriate for pumping in association with an aquifer test but are appropriate for observing the aquifer response to pumping. Wells that are to be pumped for aquifer test purposes are constructed similarly to those shown in Figures 7(b) and 7(c). It is imperative that the water level response to pumping in both the pumped and observation wells be unimpaired by the conditions in the immediate vicinity of the well. This often requires the use of the well screen surrounded by an appropriate sand or gravel pack and conscientious attention to the prevention of impairment by cement, clay, or drilling fluid.

Aquifer Tests

Aquifer tests are the primary means by which the hydraulic properties of the water-bearing zones are determined. The hydraulic properties referred to are hydraulic conductivity, K, and storage coefficient, S (or apparent specific yield in the case of unconfined aquifers). Typically, the transmissivity, which is the product of hydraulic conductivity and aquifer thickness, is obtained and the hydraulic conductivity is calculated by $K = T/b$.

Aquifer tests consist of creating an excitation in an aquifer, measuring the response to the excitation, and determining the values of T and S which cause an appropriate theoretical response function to closely match the measured response. The values of T and S so obtained are taken to be the hydraulic properties of the aquifer in the immediate vicinity of the test site. Aquifer tests vary widely in respect to the kind of excitation that is created and methods by which the data are analyzed. Only those tests most commonly used in coal mining hydrology are discussed here.

Probably the most widely used aquifer test is the one based upon the Theis (1935) equation. This test is conducted by pumping a well at a constant rate for periods ranging up to several days and measuring the drawdown of the piezometric surface in one or more observation wells located in the vicinity of the pumped well. The drawdown in the observation wells as a function of time is predicted by:

$$s = \frac{Q}{4 \pi T} W (\frac{Sr^2}{4Tt}), \qquad (11)$$

where s = drawdown (L),
T = transmissivity (L^2/T),
Q = constant pumping rate (L^3/T),
W = Theis well function (dimensionless),
S = storage coefficient (dimensionless),
r = radical distance to point where drawdown is observed (L), and
t = time (T).

The well function, W, is the exponential integral and has been widely tabulated (e.g., Wenzel 1942, Todd 1959, McWhorter and Sunada 1977, Freeze and Cherry 1979). Equation 11 is an analytical solution to Equation 10 with no recharge.

A type-curve matching procedure is used to determine the values of T and S that cause drawdown predicted by Equation 11 to agree with the observed drawdown. The type-curve is prepared by plotting the value of W against $u = Sr^2/4Tt$ on log-log paper. The values used to prepare this graph are the tabulated values given in the foregoing references. On a separate sheet of log-log paper, the observed drawdown is plotted against the corresponding value of r^2/t. The data plot is superimposed on the type-curve and adjusted until a visual best fit of the type-curve to the data is achieved. The adjustment must be done while keeping the corresponding axes of the two graphs parallel. An arbitrary point is selected (called the match point) and the coordinates of the match point from both graphs are recorded. The values of T and S are computed as shown in Figure 8.

The Jacob method is another way in which the drawdown data from such a test can be analyzed to yield estimates of T and S. For values of $u = Sr^2/4Tt$ less than 0.01, the Theis well function is closely approximated by a logarithmic relation and Equation 11 becomes

$$s = \frac{Q}{4\pi T} \{\ln (\frac{4Tt}{SR^2}) - 0.5772\}. \qquad (12)$$

The method consists of plotting the observed drawdown versus time on semi-log paper with time on the log axis. The slope of the line is used to determine T and the intercept obtained by extrapolation to s = 0 is used to estimate S. The procedure is demonstrated in Figure 9.

The aquifer test described above has been used widely for estimating transmissivity and storage coefficient of aquifers supplying water to industry, agriculture, and municipalities. The test becomes less suitable for aquifers that exhibit low transmissivities, highly variable and discontinuous stratigraphy, and fracture permeability. Unfortunately, many coal and overburden aquifers in the Rocky Mountain region exhibit all of these characteristics. Sometimes even properly planned and conducted tests have failed to provide data sufficient to justify the expense of such elaborate tests.

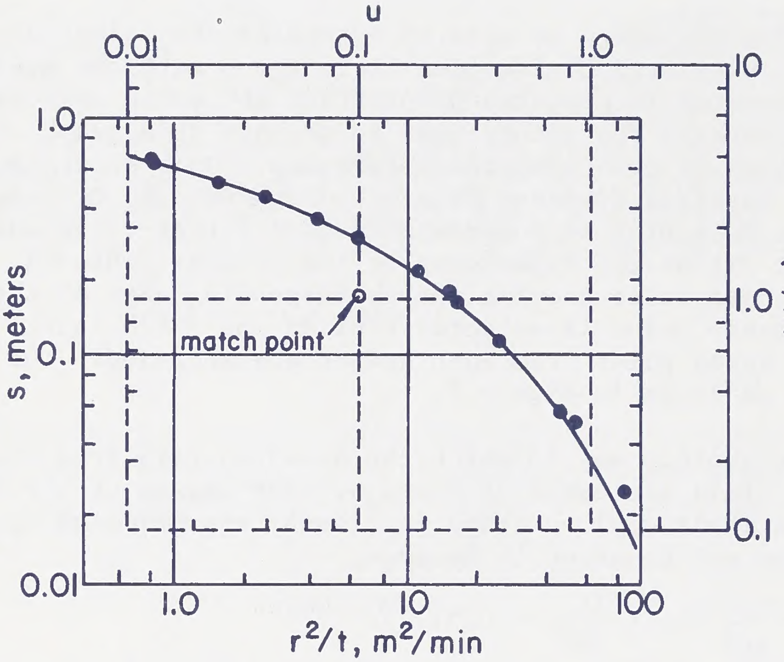


Figure 8. Type curve matching to determine aquifer properties.

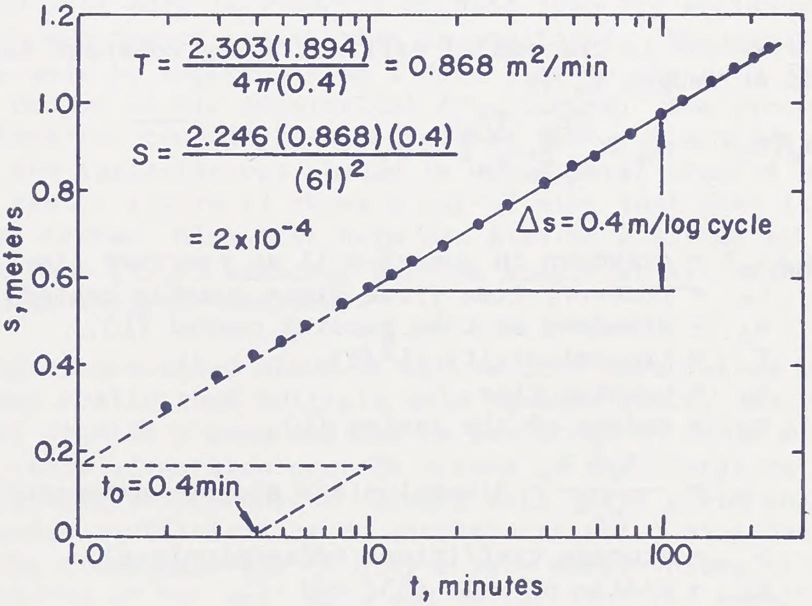


Figure 9. Jacob method for detemining aquifer properties.

A not uncommon difficulty encountered when testing zones with very small transmissivity is excessive drawdown in the pumped well, even at very small pumping rates. This can result in dewatering the well bore before significant drawdown data are obtained in the observation wells. Also, a large disparity exists between the pumping rate and the rates at which aquifer water enters the well bore in such cases. This difference, which is accounted for by depletion of water in the well bore, renders the Theis method inapplicable and causes the analysis of data to be significantly more difficult.

A theoretical response function that properly accounts for the depletion of well bore storage is available (Papadopulos and Cooper 1967) but is numerically tabulated only for drawdown in the pumped well. McWhorter (1982) extended the Papadopulos and Cooper analysis to include the prediction of drawdown in the pumped well during recovery (i.e., after pumping has ceased). Drawdown data collected in the pumped well during the pumping period are particularly sensitive to minor changes in pumping rate, especially when well-bore storage is important. Often drawdown data collected during the recovery period are much smoother and more amenable to analysis.

The theoretical drawdown in the pumped well following constant rate pumping for a time period of length t_o is

$$s_w(t_r) = s_o\, F\left(\frac{Tt_r}{r_c^2}, \frac{Tt_o}{r_c^2}, \alpha\right), \tag{13}$$

where $s_w(t_r)$ = drawdown in pumped well at recovery time t_r (L),
t_r = recovery time (time since pumping ceased),
s_o = drawdown at time pumping ceased (L),
T = transmissivity (L^2/T),
t_o = pumping time,
r_c = radius of the casing (L),
$\alpha = \dfrac{r_w^2\, S}{r_c^2}$ = dimensionless storage parameter,
S = storage coefficient (dimensionless),
r_w = radium of well (L), and
F = dimensionless response function.

The dimensionless response function F is a complicated integral and is tabulated in numerical form by McWhorter (1982) and Nazareth (1981).

Equation 13 is used in aquifer test applications as follows. The well is pumped for a few up to several hours at a constant rate and drawdown in the pumped well is monitored so that the drawdown at the moment that pumping ceases can be reliably determined. This is the value of s_o. After pumping ceases, the water level is monitored as a function of time since pumping ceased. The data are plotted on semi-log paper in the form s_w/s_o versus t_r, with t_r on the log axis. A family of type-curves is prepared by plotting s_w/s_o versus Tt_r/r_c^2 on semi-log paper for several values of the dimensionles pumping time parameter, Tt_o/r_c^2. This is accomplished using the numerical values of F tabulated in the above references for a preselected value of the storage parameter, α. The recovery of water levels in the pumped well is quite insensitive to the storage parameter, and taking $\alpha = 10^{-14}$ is recommended when the aquifer is confined. If the aquifer is unconfined, $\alpha = 10^{-1}$ will suffice.

The data plot is superimposed upon the type-curve and adjusted laterally to provide a "best fit" with one of the theoretical curves. Adjustment of the plots in the direction parallel to the vertical axis (i.e., the s_w/s_o axis) is not permitted. Once a satisfactory fit has been achieved, the transmissivity is calculated as shown in Figure 10.

Other types of single-hole aquifer tests have found use in hydrology related to coal mining. The so-called slug test as described by Cooper et al. (1967) is actually a special case of single-hole pumping test just described. It can be shown (Nazareth 1981) that Equation 13 reduces to the slug test equation of Cooper et al. as the pumping time, t_o, becomes small. In a slug test, the water level in the well bore is suddenly changed from its equilibrium position and the gradual return toward equilibrium is monitored. Determining the transmissivity is made by superimposing a data plot in the form of s_w/s_o versus t_r on the Cooper et al. theoretical type curves. The procedure is exactly as described for the single-hole pumping test. The value of s_o is the magnitude of the instantaneous change in water level created at the beginning of the test. Figure 11 shows a set of slug test data fitted to the Cooper et al. type curve. Slug test data can also be analyzed by the Hvorslov (1951) and Bouwer-Rice (1976) methods, but the Cooper et al. method is to be preferred from a theoretical viewpoint.

The single-hole tests described above do not require observation wells and, therefore, are less costly than multiple well aquifer tests. Furthermore, the slug test does not require a pump and can be performed on small diameter wells. However, these advantages must be viewed in consideration of the disadvantages of single-well methods. Single well tests yield only rough estimates for storage coefficient or no estimate at all. Slug test response is a measure of the transmissivity in only a very small volume of aquifer in the immediate vicinity of the well bore and is particularly sensitive to the "skin effect" (i.e., to permability impairment or enhancement near the well bore). Recovery data collected in the pumped well following a prolonged pumping period are influenced by the transmissivity in a much larger volume of aquifer but remain sensitive to permeability impairment.

The discussion of aquifer tests to this point has concentrated on the determination of the hydraulic properties of the pumped aquifer. The areal extent and magnitude of drawdown in an aquifer as the result of mining are sometimes limited by leakage through the confining aquitards. Aquifer tests can be used to estimate the vertical hydraulic conductivity of adjacent aquitards in some instances. Hantush's (1956) theoretical response function for a leaky aquifer can be written in the format of the Theis solution:

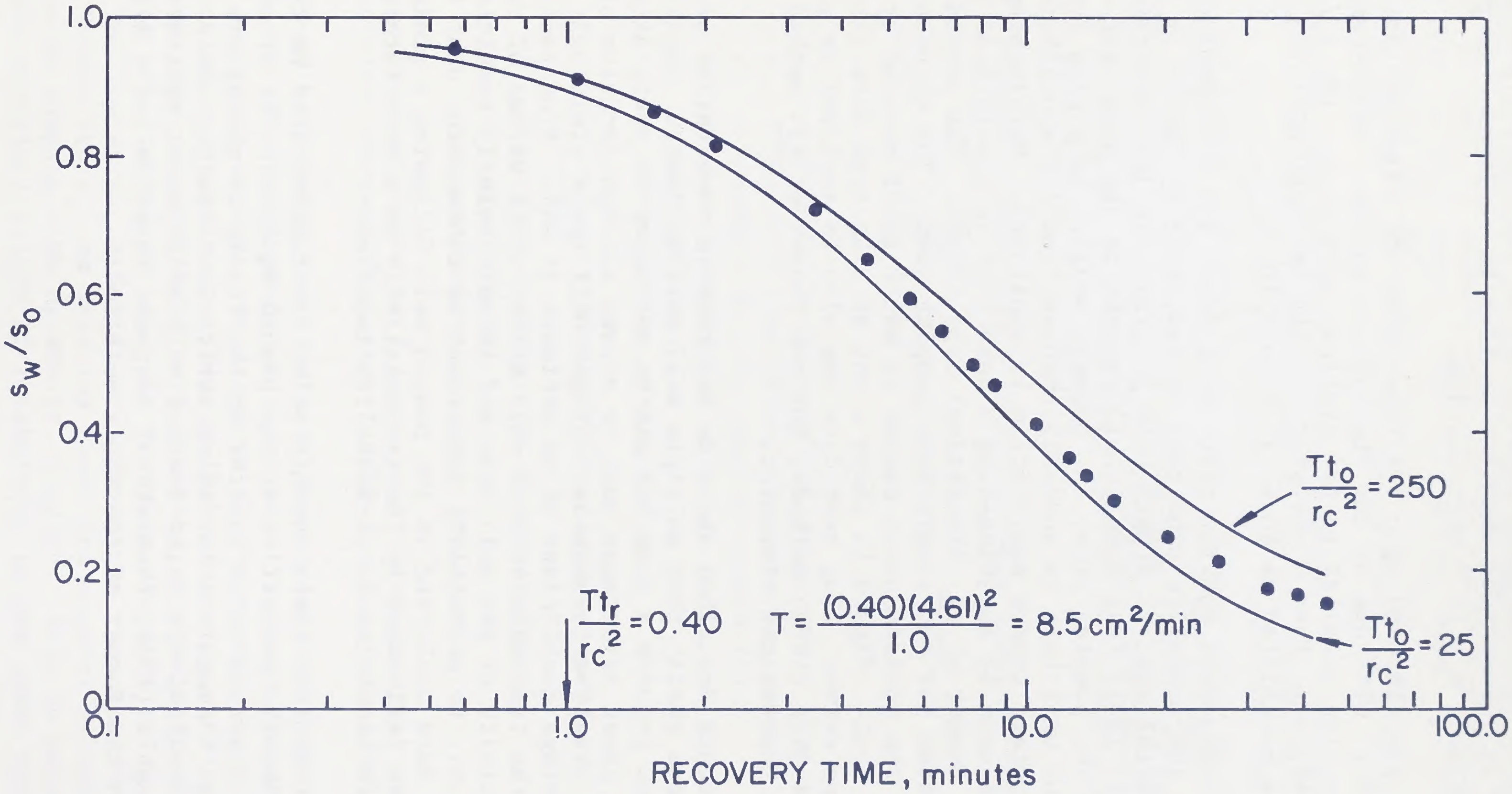


Figure 10. Analysis of recovery data affected by well bore storage.

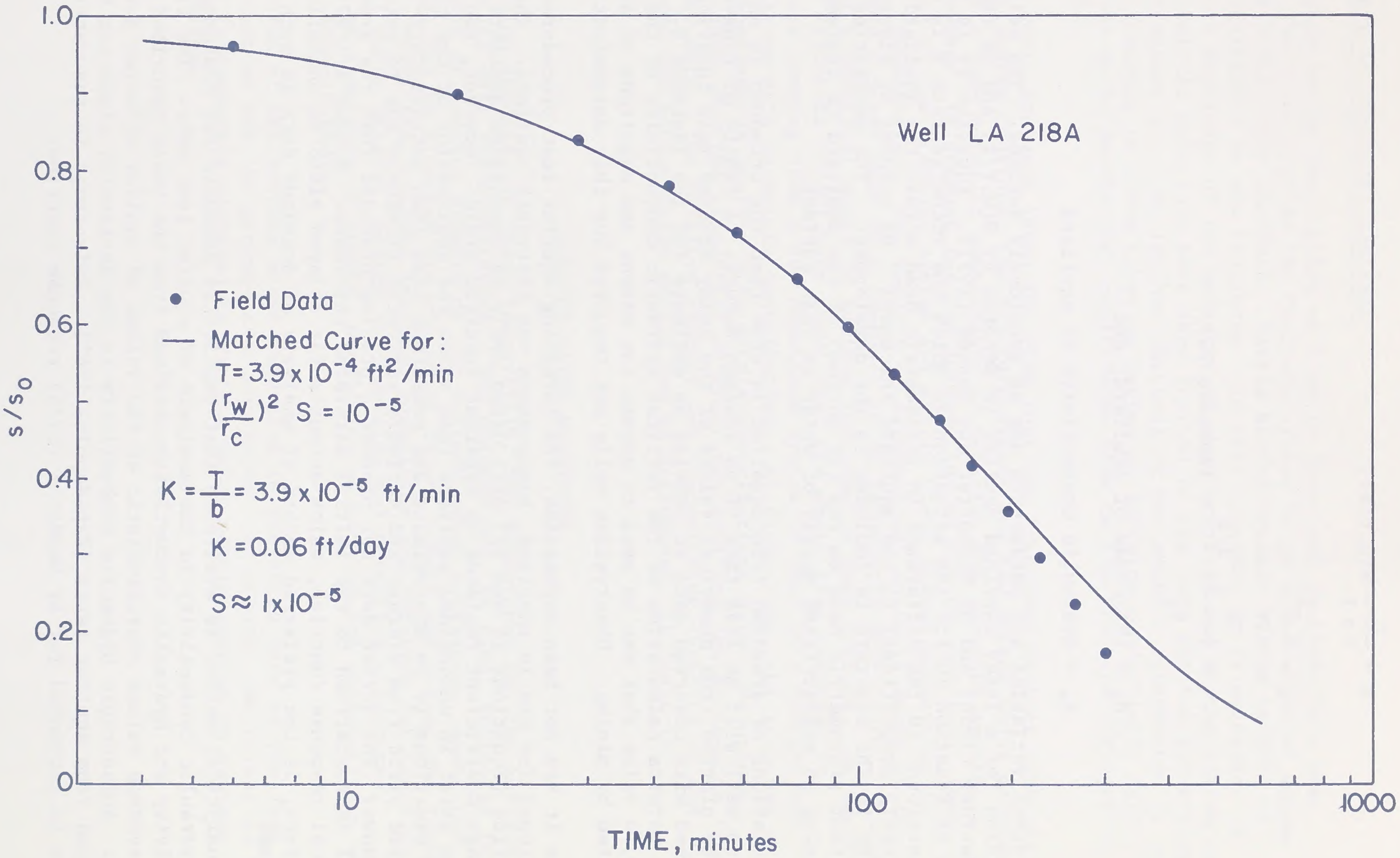


Figure 11. Matching the aquifer response to a slug test.

$$s = \frac{Q}{4\pi T} W(u, r/B), \tag{14}$$

where $u = \frac{s\ r^2}{4Tt}$,

$B = \left(\frac{Tb_a}{K_a}\right)^{1/2}$ = leakance (L),

b_a = thickness of aquitard, and

K_a = hydraulic conductivity of aquitard

and other variables and parameters are as previously defined. The well function for a leaky confined aquifer is denoted by W(u,r/B) and is tabulated by Hantush (1956) and by McWhorter and Sunada (1977). Equation 14 is a solution of Equation 10 for the situation in which the recharge rate W is directly proportional to the difference in piezometric head across the aquitard and inversely proportional to the aquitard thickness. No account of storage change in the aquitard is included in the development. The assumption of a constant piezometric head on top (or bottom) of the aquitard is tantamount to assuming an unrestricted supply of water to that surface.

Calculations of drawdown from Equation 14 show that the drawdown in an observation well will be less than if no leakage occurs. A family of type-curves can be plotted from numerical values of the leaky aquifer well function and matched with observed data to provide an estimate for the leakance B. This in turn permits calculation of the vertical hydraulic conductivity of the aquitard, a value that can be used to assess the extent and magnitude of drawdown created by mining. Observation wells are required for this determination.

While it has not been emphasized, the foregoing aquifer test procedures were developed for use in confined, homegeneous and isotropic aquifers. The Theis solution (Equations 11 and 12) will often apply to unconfined aquifers with storage coefficient replaced by apparent specific yield. However, two conditions exist in unconfined aquifers that cause the application of the confined flow equations to be approximate and sometimes less than satisfactory---delayed yield from storage and variable saturated thickness due to water table drawdown. The latter does not present a problem provided that the drawdown is small in comparison to the initial saturated thickness. Neuman's (1975) theoretical response function, which accounts for delayed yield in unconfined aquifers, is the preferred method of analysis of drawdown data in such systems.

No analytical method is available that explicitly accounts for nonhomogeneity of hydraulic conductivity in the analysis of aquifer test data. The transmissivity and hydraulic conductivity obtained from the tests described above are average values characteristic of the volume of aquifer affected during the test. Anisotropic hydraulic conductivity in the horizontal plane can be deduced from aquifer tests (Papadopulos 1965). Anisotropy in the vertical plane is accounted for by Neuman's (1975) response function.

Aquifer Tests in Fractured Aquifers

Two approaches to the description of flow in fractured aquifers have been utilized. The first regards the fracture system as an interconnected network of individual flow channels. Matrix blocks bounded by the network of fractures contribute to the fractures. In this approach it is necessary to have explicit knowledge of the geometry of each fracture and of the system as a whole. Analytic solutions have been limited to the very special geometries of a single planar fracture (either vertical or horizontal) intersected by the well. The fracture is often taken as having an infinite conductivity relative to the porous media matrix that contributes flow to the fracture (Gringarten et al. 1974).

The second basic approach takes the view that the fractured aquifer consists of two overlapping continua, the fracture system and the porous media matrix system. This view makes it unnecessary to describe the fracture system in detail. However, to account for the interaction of the two continua, some idealization of the fracture system and matrix block system geometries is necessary. Nevertheless, the results of mathematical analysis based on the two-continuum concept show this approach to be inherently more useful. Kazemi (1969) used a numerical model to analyze the flow in such systems. De Swaan (1976) and Najurieta (1980) have shown that the small time response to constant rate pumping from a two-continuum system is that of a homogeneous fracture system with no matrix contribution. At large time, the response is that of a homogeneous aquifer with matrix contributions only. Najurieta (1980) has shown how the properties of fractured aquifers can be deduced from aquifer test data. The relative storage and transmitting capacity of the fractures and the porous media matrix can be determined, at least in principle.

SURFACE WATER SUBSYSTEM

Surface mining changes, at least temporarily, the topography and the surface and subsurface soil characteristics. The changes are, in turn, reflected in modifications of several aspects of the surface water subsystem. Among the aspects that may be affected are volume of direct runoff and timing and routes of runoff. Predicting changes in these quantities are required for input to the overall water balance, design of diversion and retention structures, prediction of chemistry of runoff, prediction of erosion and sedimentation and design of sediment ponds.

The discussion of the surface water subsystem is presented here in the same general format as was the ground-water subsystem. As before, the intent is to review the fundamentals utilized in surface water models applied to surface mining problems.

Precipitation Excess

Precipitation is the primary input to models of the surface subsystem. A major task faced by the hydrologist dealing with mining-related problems is to quantify the relationship between precipitation and direct runoff. The volume of direct runoff is reduced relative to the volume of precipitation by evaporation, interception, and infiltration. Precipitation excess is the instantaneous difference between the precipitation rate and the summed rates of the above processes. The cumulative volume of precipitation excess becomes the volume of direct runoff. The time distribution and total volume of direct runoff, both on a per-storm and annual basis, are usually required.

Precipitation

Precipitation is derived from atmosphere waters and occurs in the form of rain, snow, and hail. Precipitation varies spatially and temporally during individual storms and annually. This variability, which is often extreme, is a primary difficulty in hydrologic modeling. Precipitation is measured at specific points and data from several points are used to estimate the time and space variability over an area of interest. A common method for depicting the areal distribution of precipitation is the isohyetal method (Viessmann et al. 1977). An isohyetal map shows lines of equal precipitation in a way analogous to the depiction of the piezometric head distribution by a piezometric surface map or topography by a topographic map. Isohyetal maps may be prepared for total precipitation, for a particular storm, or for average precipitation over any interval of interest.

Precipitation input to hydrologic models may require characterization of the temporal variation of precipitation intensity for individual storms and daily, annual, or mean annual precipitation. The manner in which the time variation of precipitation is characterized depends centrally on the purposes of the computation. Design of diversions, retention ponds and other hydraulic structures usually requires that the variation of precipitation intensity for particular storms be known. For calibration and testing, measured storm intensities and durations can be used. For prediction the characteristics of a hypothetical storm are used. Individual storms can be classified acccording to total precipitation and duration; various methods can then be used to synthesize the time distribution of intensity for a selected storm. The U.S. Department of Commerce (1963) has published contour maps showing the spatial distribution of total precipitation for storms of specified duration and frequency of occurrence. Haan and Barfield (1977) gave several examples of how rainfall intensity can be synthesized for a particular storm.

Quite apart from the problem of precipitation variation for a single event is the characterization of total precipitation on a daily, monthly, etc. basis. Time series analysis is a common method of attack for such problems (Viessman et al. 1977). A time series is the sequential occurrence of events under consideration. For example, time series of daily precipitation is a sequential record of daily precipitation amounts. An important use of the time series in the context of this paper is to provide a synthetic record of precipitation that can be used to drive sequential hydrologic models. A meaningful discussion of generation of synthetic time series of precipitation by time series analysis requires the introduction of several concepts from probability and statistics and is deemed beyond the scope of this paper. Haan (1977) provides a good discussion of time series analysis and data generation techniques.

Infiltration

Other than precipitation itself, the single most important determinant of precipitation excess is infiltration. Infiltration is controlled by the supply of water at the surface and by the hydraulic properties and moisture conditions of the soil. Therefore, estimation of this link between the surface and soil water subsystems falls within the context of both subsystems.

Water from the ground surface moves into the soil in response to gravitational force and the force resulting from differences in pressure (i.e., a pressure gradient). The pressure gradient, in turn, results from capillarity and is large when the initial water content of the soil is small. As the water content of the soil increases, the driving force due to capillarity becomes small and approaches zero as the soil approaches saturation. It is the decrease in driving force due to capillarity that is responsible for the decrease in infiltration rate shown in Figure 12. The essentially constant infiltration rate approached by the curve at large time is the base intake rate. The only driving force for infiltration at large time is gravity.

An infiltration equation with a relatively firm foundation in physical theory is that of Philip (1957):

$$i = A\ t^{-1/2} + K, \tag{15}$$

where i = infiltration rate (volume per unit area per unit time),
t = time (T),
K = hydraulic conductivity (L/T), and
A = sorptivity ($LT^{-1/2}$).

The sorptivity is a coefficient strongly dependent upon the hydraulic conductivity of the soil and the antecedent (initial) water content. The sorptivity is a maximum when the antecedent water content is small and is zero for a soil that has been subjected to prolonged wetting. Small hydraulic conductivity also causes the sorptivity to be small. All of the parameters in Equation 15 have a definite physical significance and can be calculated from other data under ideal conditions. The inherent variability of hydraulic conductivity and antecedent water content usually precludes such calculations, however, and the constants in the infiltration equation become adjustable parameters determined by model calibration.

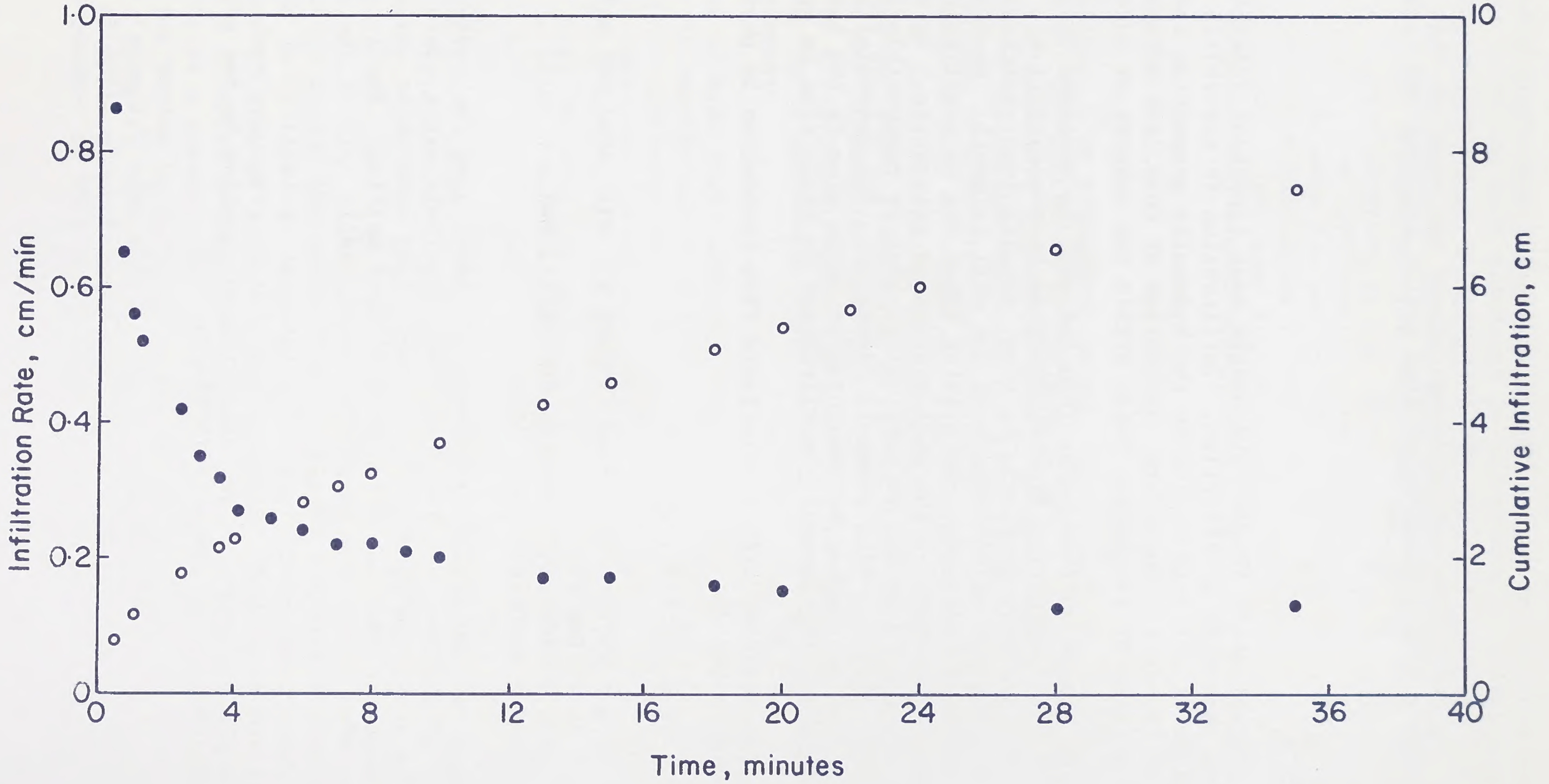


Figure 12. Example of an infiltration curve.

Equation 15 is one of a substantial list of infiltration equations that have found use in modeling work. Among others, have been the Horton, Green-Ampt, and Holtan equations, discussed by Viessman _et al_. (1977). None of these is as firmly grounded in physical theory as the Philip equation given above but all predict the general shape of the infiltration curve shown in Figure 12. Infiltration has been intensively studied in recent years and new methods for calculating infiltration rates have been developed. To the author's knowledge, these have not yet found widespread use in watershed modeling and will not be presented here.

Other Approaches

Calculation of rainfall excess by the method described above involves the simple subtraction of the infiltration rate from the precipitation intensity at corresponding times during the storm. The parameters of the infiltration equation and the time variation of precipitation intensity are required. The data are difficult and costly to obtain, especially if the option of calibration is not available as is often the case in predictive problems. Other methods that do not require such detailed information are available and have found a great deal of use in mining hydrology.

The Soil Conservation Service (SCS) method calculates the total volume of direct runoff (rainfall excess) from a particular storm (USDA 1968, 1973) utilizing only the total volume of precipitation and a parameter that depends upon soil type, land use, and an antecedent water content condition. The SCS formula is

$$V = \frac{(P-0.2S)^2}{P+0.8S}, \qquad (16)$$

where V = volume of direct runoff per unit area (L),
P = depth of precipitation (L), and
S = maximum potential abstraction (L).

The parameter S accounts for such factors as depression storage and infiltration capacity, although indirectly, through its relation to soil classification, land use and antecedent water content conditions. The value of S to be used for a particular storm is obtained by first determining the watershed curve number (CN). Extensive charts relating CN to land use, cover, hydrologic condition, antecedent moisture, and soil type are available to be used as guides for selecting the appropriate value of CN (USDA 1968, Viessman _et al_. 1977, Haan and Barfield 1978). Composite curve numbers for heterogeneous watersheds can be calculated.

The simplicity of Equation 16 and the procedures for determining the value of S are very attractive and probably account for their widespread use. Often the precipitation used in Equation 16 is the readily available daily rainfall. A stochastic time series of daily rainfall developed from the historical records can be used as input to Equation 16 to obtain a stochastic time series of direct runoff from which trends and long-term averages can be estimated. It should be noted, however, that a great deal of judgment is required in the selection of the watershed curve number. Also, estimation of rainfall excess with no consideration of variable rainfall intensity and duration is a rather drastic simplification. Observed runoff shows a great deal of scatter around the curve predicted by this method.

Routing Precipitation Excess

Runoff from a watershed is observed at one or more gaging stations where the instantaneous discharge and stage are measured. Routing refers to the method by which the instantaneous discharge through a channel cross section is related to the occurrence of rainfall excess on the watershed above the section of interest. Routing of both channel and nonchannel (overland) flow is required.

Hydrograph Methods

A hydrograph is the record of instantaneous discharge as a function of time. The area under the hydrograph curve is the total volume of runoff and may include both direct runoff and base flow contributions from ground water.

The concept of a unit hydrograph has found a great deal of use in relating precipitation excess to the timing of direct runoff. A unit hydrograph is the relation between the instantaneous runoff discharge and time for a unit value of rainfall excess. Direct runoff for rainfall excess other than unity is calculated by multiplying the ordinates (discharge) of the unit graph by the rainfall excess of interest. Unit hydrographs can be derived from measured runoff or by a variety of estimation techniques. Implicit in the unit hydrograph method is the assumption that the relative rainfall intensity variation and the spatial distribution are identical for all storms. The rather limiting assumption that the temporal distribution of rainfall intensity is the same for all storms can be circumvented by use of the instantaneous unit hydrograph.

The instantaneous unit hydrograph is the relation between runoff discharge and time in response to a unit rainfall excess that comes instantaneously into existence. The direct runoff in response to variable rainfall excess can be expressed in terms of the instantaneous unit hydrograph by:

$$Q(t) = \int_0^t g(\tau)\, i(t-\tau)d\tau, \qquad (17)$$

where
$Q(t)$ = runoff discharge per unit area at time $t(L/T)$,
$g(\tau)$ = dimensionless ordinate of the instantaneous unit hydrograph, and
$i(t-\tau)$ = intensity of rainfall excess at time $t-\tau$ (L/T).

Instantaneous unit hydrographs can be developed from measured runoff or synthesized.

The great utility of the unit and instantaneous unit hydrograph methods for relating precipitation excess to runoff discharge derives from the fact that the important watershed parameters controlling the relationship are incorporated into the unit graph. When the unit response functions can be derived from measured runoff, explicit consideration of the many variables and parameters affecting the response is not required. However, in the context of this paper, predictions of changes in the watershed response to mining are of fundamental importance. This in turn requires that estimation of the effects of mining on the unit response be made from a knowledge of factors controlling the response. Methods by which this can be accomplished are presented in the following paragraphs.

Hydrodynamic Methods

Hydrodynamic methods are based on a water balance written for a differential control volume coupled with an appropriate momentum equation. This is completely analogous to the development of the equations of ground-water flow accomplished by combining a water balance expression with Darcy's law. Darcy's law is actually the appropriate momentum equation for flow in porous media.

The momentum equation applicable to overland and channel flow can be written in general terms involving full consideration of local and convective acceleration and gravity, pressure, and frictional forces. A much simpler expression that neglects the dynamic forces of local and convective acceleration is commonly used in watershed models. If dynamic forces are neglected, the friction slope becomes equal to the slope of the channel or overland flow surface. This, in turn, permits one to write an expression relating the discharge and depth to the bed slope. This approach is called the kinematic method because the dynamic effects are neglected.

The kinematic method permits one to relate the discharge and flow depth in overland flow to the surface slope by:

$$q^2 = \frac{8gS_o}{f} y^3, \qquad (18)$$

where q = discharge per unit width (L^2/T),
g = gravitational constant,
S_o = slope of overland flow surface (dimensionless),
y = depth of flow (L), and
f = dimensionless Darcy-Weisbach friction fractor.

For channel flow, the corresponding equation is usually the Manning or Chezy equation, although the Darcey-Weisbach equation given above may also be used.

These familiar equations are not repeated here because Equation 18 demonstrates the salient feature that discharge is a power function of depth. The friction factor f is related to the Reynolds' number of the flow and to the hydraulic roughness of the flow surface or channel.

A differential water balance for overland flow is:

$$\frac{\partial q}{\partial x} + \frac{\partial y}{\partial t} = i(x,t), \tag{19}$$

where q = discharge per unit width of slope (L^2/T),
y = depth of flow,
i = rainfall excess (L/T),
x = coordinate direction measured parallel to slope (L), and
t = time (T).

Combining Equations 18 and 19 results in

$$\alpha\beta\, y^{\beta-1} \frac{\partial y}{\partial x} + \frac{\partial y}{\partial t} = i(x,t), \tag{20}$$

where α and β are constants that are related to the slope of the overland flow surface and a resistance or roughness parameter. Equation 20 is called the kinematic wave equation and can be solved by numerical or analytic techniques. An expression of identical mathematical form can be developed for flow in the channel. For channel flow the term "i" is interpreted as lateral inflow to the channel from tributaries and overland runoff. Also, Equation 20 is usually written in terms of discharge for channel flow rather than flow depth as was done above.

In watershed modeling applications, solutions to Equation 20 (or its counterpart for channel flow) are obtained for segments or subelements of a watershed, the outflow from one element adding to the flow in downstream elements. In this way heterogeneous watersheds can be handled by using different elements. For example, spatially varied precipitation excess resulting from spatially varied precipitation intensity and/or infiltration characteristics can be given full consideration. If the infiltration capacity, overland flow resistance coefficient, or channel geometry of one or more elements of the watershed are modified by mining, these changes can be incorporated into the calculation, at least in principle.

SOIL WATER SUBSYSTEM

As discussed in the previous section, infiltration is the primary link between the surface and soil water subsystems. No further consideration of infiltration will be given here. Instead, the emphasis in this section is on computation of the outflow components of the soil water subsystem--evapotranspiration and deep percolation. A water balance for the soil water subsystem can be written for macroscopic or differential control volumes as was the case for the surface and ground-water subsystems. The following discussion will include both approaches.

Macroscopic Water Balance

The water balance for the soil water subsystem, written for the entire rooting depth and a unit area, can be expressed as:

$$I - E_{ta} - W = \frac{\Delta\overline{\theta}}{\Delta t}, \qquad (21)$$

where I = average infiltration rate over t (L/T),
E_{ta} = average evapotranspiration rate over t (L/T),
W = average deep percolation rate over t (L/T),
$\Delta\overline{\theta}$ = change in stored volume per unit area (L), and
Δt = time interval (T).

Frequently, one attempts to calculate W from Equation 21 by evaluating all of the remaining terms. Time periods over which Equation 21 are commonly applied from 1 day to 2 year.

In the arid and semiarid regions of the Western United States, the potential evapotranspiration is greater than the cumulative infiltration on an annual basis. Since the potential evapotranspiration is greater than the infiltration, one might be tempted to conclude the $E_{ta} = I$ on an annual basis and, therefore, that $W=0$. However, the timing of infiltation relative to that of evapotranspiration can cause this conclusion to be in error. For example, infiltration resulting from spring snowmelt may exceed the low transpiration potential in the spring sufficiently to make up any storage deficit and result in deep percolation. The time period Δt over which Equation 21 is applied must be small enough to account for the major variations in the timing of infiltration and evapotranspiration.

Evapotranspiration

Evapotranspiration refers to the combined processes of direct evaporation from the soil and evaporation from the stoma of plants growing in the soil. Evapotranspiration depends upon the energy available for evaporation, vapor pressure, air temperature, wind, type of plant and stage of growth, and availability of soil water. A through discussion of the evapotranspiration process and computation methods is provided by Jensen (1973).

It is convenient to define three rates of evapotranspiration. (1) Potential evapotranspiration is defined as the rate of evapotranspiration from a well-watered reference crop. Lake evaporation is also commonly regarded as the potential evapotranspiration. Potential evapotranspiration can be computed with considerable accuracy from one of several methods: Penman, Jensen-Haise, Blaney-Criddle, Thornthwaite, etc. Different methods require different input data and the method selected for use should be commensurate with the data available. The Penman method is probably the most firmly grounded in physical theory but also requires substantial data input for its use. Potential evapotranspiration can be calculated for time intervals as small as one day, although all methods are not uniformly satisfactory for that purpose.

The potential evapotranspiration is adjusted by a crop coefficient to give the evapotranspiration of a particular vegetal cover when the availability of soil water does not limit the evapotranspiration process.

(2) Evapotranspiration for a specific cover when water is not limiting is the second definition referred to above. It is given by:

$$E_t = K_c E_{tP}, \tag{22}$$

where E_t = evapotranspiration for a specific vegetal cover with water not limiting,
E_{tp} = potential evapotranspiration, and
K_c = crop or cover coefficient.

The coefficient K_c is not a constant; rather it varies seasonally and with crop stage. Wymore (1974) gives values for K_c for nonagricultural crop covers. Values for agricultural crops are given by Jensen (1973).

(3) The third rate of evapotranspiration is the actual rate as limited by soil water availability. The symbol E_{ta} is given to this rate and appears in Equation 21. It is obvious that the evapotranspiration cannot exceed the water available over any time period. Water availability limits the actual seasonal volume of evapotranspiration in all of the Western coal-producing regions. Various investigators have attempted to relate E_{ta} to E_t through a function of the water content in the soil. Probably the most practical method assumes that evapotranspiration proceeds unrestricted until the water content of the soil is reduced to a critical level. Evapotranspiration is assumed to cease when this critical level is reached. The water balance Equation 21 can be used to determine if and when the critical level is reached. These concepts are discussed further in the following paragraphs.

Soil-Water Storage

The maximum quantity of water that can occupy the soil is limited by the porosity. A very wet soil tends to drain until the water content reaches a value called field capacity. Because the water content of a soil cannot be reduced below field capacity by gravity drainage, field capacity plays an important role in determining the quantity of water held in a soil and, thereby, making water available for uptake by the plant root system. Water contained in the soil at water contents greater than field capacity will drain within a few hours to a few days and not contribute significantly to the reservoir of storage that supplies the plant uptake demand.

As indicated previously, there is a lower limit of water content below which evapotranspiration is practically zero. This critical water content is called the permanent wilting water content. The difference between field capacity and the permanent wilting water contents, multipled by the depth of rooting, is called the available water capacity of soil. Note that water which readily drains from the soil and water held too tightly to permit uptake by plant roots are excluded from the available water capacity.

Water which infiltrates the soil will tend to redistribute and make up any deficit in the available water reservoir. If the infiltrated volume is sufficient to make up the entire deficit, then deep percolation can occur. Otherwise the infiltrated volume will be stored until used by the plants. The macroscopic water balance equation can be used to keep track of the quantity of water in the available water reservoir as indicated by the following example.

Suppose the available water capacity for a soil is 9 cm and that a deficit of 3 cm exists at the beginning of a month for which $I = 10$ cm and $E_t = 6$ cm. the infiltrated volume is sufficient to make up the entire deficit of 3 cm and to resupply the 6 cm taken from storage by evapotranspiration during the month. Thus, for this particular month, $\Delta\bar{\theta} = +3$ cm, $E_{ta} = 6$ cm, $I = 10$ cm and by difference, $W = 1$ cm. Furthermore, the next month is begun with no deficit in the available water reservoir. Suppose that $I = 3$ cm and $E_t = 15$ cm for the next month. The evapotranspiratin demand (E_t) is 15 cm but a total of only 12 cm exists available to meet the demand (9 cm in storage plus 3 cm of infiltration). Therefore, the demand cannot be met and the actual evapotranspiration is limited to $E_{ta} = 12$. Also, $\Delta\bar{\theta} = -9$ cm, $I = 3$ cm and $W = 0$. The third month will be begun with no water held over in storage. This process is continued for each month to obtain the annual soil water balance.

Differential Water Balance

The macroscopic water balance equation gives no information on the soil-water dynamics. By combining, a water balance written for a differential control volume with Darcy's law, a partial differential equation describing the flow in the soil water subsystem can be developed:

$$\frac{\partial}{\partial z}\left(K \frac{\partial h_c}{\partial z}\right) - \frac{\partial K}{\partial z} \quad \frac{\partial \theta}{\partial t}, \tag{23}$$

where K = hydraulic conductivity (L/T),
h_c = capillary pressure head (L),
θ = volumetric water content (dimensionless),
z = vertical coordinate measured postive upward (L), and
t = time (T).

Equation 23 is called the Richard's equation. The hydraulic conductivity has the same significance here as for flow of ground water in a saturated aquifer. However, the soil water zone is typically unsaturated and K is a strong function of the volumetric water content θ. The capillary pressure head, h_c is also a function of θ. In mathematical terms, Equation 23 contains three dependent variables: K, h_c and . A solution is possible only if two additional, independent relationships among these variables are available.

The additional two relationships required for solution of Equation 23 are called the capillary hydraulic properties. In very general terms they are $K(\theta)$ and $h_c(\theta)$, or alternatively, $K(h_c)$ and $\theta(h_c)$. Use of the first two relationships together with Equation 23 leads to the water content form, and use of the latter two relationships leads to the pressure head form. Regardless of whether the water content or pressure head form is used, the capillary hydraulic properties must be known. The capillary hydraulic properties must be measured, either in the laboratory or the field. The difficulty and expense of characterizing the capillary hydraulic properties at a single location, let alone the spatial variation, are substantial constraints on the use of this approach in field-oriented modeling efforts.

In the form given by Equation 23, no consideration is given to water uptake by roots. Water uptake by the plant root system is simulated by adding a sink term to the right side of Equation 23. The sink term has the physical significance of being the volume of water removed per-unit volume of soil per-unit time. Several different methods of quantifying the sink term have been used. Probably the most practical method has been to calculate the evapotranspiration by one of the procedures discussed previously and then to distribute the uptake over the rooting depth. In other words, the quantity and time distribution of water uptake are calculated from familiar evapotranspiration formulas; location of the uptake within the soil is simulated by assuming some distribution, usually based upon knowledge of the root density distribution. A second approach to the inclusion of evapotranspiration in the soil water flow equations is to formulate the sink term from physical considerations of the mechanics of uptake by roots (e.g., Nimah and Hanks 1973).

WATER QUALITY

A major concern relative to the hydrologic impact of surface mining is the effect on water quality. The inorganic water chemistry of ground water can be affected through a number of mechanisms. Surface mining disrupts the natural sequence of geologic strata and replaces it with an unconsolidated rubble that is a complex mixture of the original geologic materials. Materials isolated from contact with water or below the zone of aeration prior to mining may be placed where they are readily accessible to air, water, and other weathering agents. Communication of waters of different quality from previously separated strata can occur through spoil backfill. Waters entering aquifers and streams after contacting the disturbed geologic materials may be substantially more mineralized than prior to mining. The difficulities of gaining an understanding and quantitative description of the effect of mining on water quality include all of those associated with the geology and hydrology plus those relating to chemical and physical interactions among water, gases, and solids.

Water quality as used herein encompases the entrainment of suspended solids as well as dissolved solids. Sediment removal from disturbed lands may have an adverse effect on the biologic and hydraulic regime of surface waters receiving the sediment load. For this reason, erosion assessment and control is an important use of models in surface mining hydrology.

Inorganic Water Quality

Ground-water contaminating refers to the introduction of one or more contaminants into the ground-water system. Implicit in this use of the term is the assumption that the contaminant is foreign and has a source external to the natural system. Examples are seepage from a uranium tailing impoundment, landfill, or other waster disposal site. Ground-water contamination problems of this sort are relatively unimportant in surface mining hydrology. The more important water quality problem to be addressed involves the question of chemical changes that result, not from the introduction of foreign substances, but from the disturbance itself. Thus, an understanding of the evolution of water quality in the ground-water system is of primary importance.

Evolution of Water Quality

Essentially all ground water was derived from atmospheric sources. The chemical composition of the ground water at a given time and place depends upon the chemistry of the originating precipitation, the time and distance the water has traveled through the earth's crust, degree of mixing with other waters, and the distribution of strata and minerals encountered along the flow path.

From the viewpoint of the evolution of water quality, one of the most important zones along the flow path is the soil water zone, where weathering and biological agents are most active in the transformation of water quality. The soil water zone is characterized by the presence of relatively large quantities of organic matter and gases. Decay of organic matter and respiration of plant roots produce CO_2 which combines with water to form H_2CO_3 (carbonic acid). Minerals are dissolved in the soil water containing processes of organic matter decay and plant root respiration replenish the CO_2 and a continuing supply of acidity is available (Freeze and Cherry 1979).

Continued mineral dissolution in the soil water zone eventually creates a relatively well leached body of geologic material and waters entering the ground-water system from this zone often exhibit fairly low mineralization. One effect of surface mining is to replace this zone with relatively fresh geologic materials and, thereby, replenish the supply of minerals available for dissolution.

As ground water moves through the saturated zone, the chemical composition undergoes further change. There is a general tendency for the dominant anion to change from bicarbonate in the active recharge zones to sulfate in less active zones and finally to chloride in zones of very sluggish ground-water movement. This sequence is usually accompanied by an increase in total dissolved solids (Domenico 1972). The most common sources of sulfate are gypsum and anhydrite, while chloride is contributed by halite and sylvite.

According to Freeze and Cherry (1979), one of the most important determinants of the chemical evolution of ground water is the order in which materials of different mineralogical composition are encountered by the moving ground water. These authors demonstrate that very distinctly different chemcial composition evolves in waters passing through a sequence of soil, limestone, gypsum, sandstone, and shale, depending upon the order of encounter. One of the most obvious effects of surface mining is to disrupt the natural order of encounter.

A conceptual model of the hydrogeochemical processes controlling the evolution of ground water in the Northern Great Plains region is reported by Groenewold et al. (1980). They view the evolution of ground-water quality in both the premining and postmining phases as being controlled by oxidation of pyrite and organic matter in the soil, dissolution of carbonate minerals, precipitation and dissolution of gypsum, cation (Na, Ca, Mg) exchange, and reduction of sulfate. The unsaturated, soil water zone is regarded as the most important zone from the standpoint of affecting ground-water quality. The relative abundance and distribution of pyrite, gypsum, calcite, dolomite, and clay minerals (being the key minerals in this model) are thought to explain the observed variability of ground-water quality.

The above model provides the basis for estimating (in a qualitative way) the consequences of mining, accomplished by associating the major contributors to mineralization of waters with the occurrence of the host sediments in the overburden. The potential for water quality degradation resulting from the disturbance of the overburden can then be assessed. For example, Groenewold et al. (1980) suggest that the potential for producing highly mineralized ground water is great when the overburden to be disturbed is predominantly flood basis sediments that contain finely disseminated pyrite and sodium-montmorillonite clays. Their model indicates that high levels of sodium and sulfate ions are to be expected in such a situation. The sodium is expected to result from the replacement of sodium by calcium and magnesium on the exchange sites in the clay and the sulfate from the oxidation of pyrite.

Other conceptual models of the evolution of ground-water chemistry are in essential agreement with that described above. There is general agreement that the soil water zone is probably the most active zone in this context and that the abundance and distribution of calcite, pyrite, gypsum, dolomite, and clays (particularly montmorillonite) are of primary importance (Dollhopf et al. 1981, Hounslow et al. 1978, Hounslow et al. 1979). However, the problem of quantitatively predicting the water quality remains. McWhorter et al. (1979) found that the overall salt status in spoil water (EC, TDS, and major ion concentrations) could be predicted reasonably well from measurements in saturation extracts prepared from the spoil material. The data from saturation extracts also agreed satisfactorily with leachate data collected from leachate collectors buried in the field. Van Voast et al. (1978) also suggested that column leaching and saturated paste extracts are useful for assesing the salt status of spoil water. Dollhopf et al. (1981) indicated that water column-extracted chemistry may provide predictions of postmining water quality as characterized by the trace metals manganese, cadmium, copper, lead, zinc, and nickel.

Transport Mechanics

Prediction of the distribution of chemical species in subsurface flow depends upon the rates and patterns of flow in addition to the factors discussed above. A particular dissolved species orginating at a given location will become spatially dispersed as a result of the water movement. Disregarding any tendency for the species to interact with the solid or with other chemicals in the solution, the distribution of the "tracer" species in the aquifer is controlled by three processes: convective (advective) transport along the macroscopic paths of ground-water flow, microscale mixing caused by variable fluid element velocities within the porous structure, and molecular diffusion.

As in previous developments outlines in this paper, the mathematical differential equation describing the distribution of the tracer species is based on the mass conservation principle and a constitutive relationship. For the case at hand, the constitutive relation is Fick's law and is used to describe both the molecular diffusion and the microscale mixing due to velocity variation. The resulting differential equation is called the equation of hydrodynamic dispersion (Bear 1972) and, for the one-dimensional case, is:

$$\frac{\partial}{\partial x}\left(D \frac{\partial C}{\partial x}\right) - \frac{\partial}{\partial x}(v\ C) = \frac{\partial C}{\partial t} + S \, , \qquad (24)$$

where D = longitudinal coefficient of dispersion (L^2/T),
C = concentration of trace species (M/L^3),
v = seepage velocity (L/T),
x = space coordinate (1),
t = time (T), and
S = source/sink ($M/L^3 \cdot T$).

The dispersion coefficient D includes the effects of diffision and microscale mixing, the combined processes being known as hydrodynamic dispersion. The second term on the left of Equation 24 accounts for the transport of the tracer species along the ground-water flow path.

The source/sink term S requires further discussion. It is this term that accounts for the many chemical and physical interactions that the tracer species may experience. To characterize these complex interactions by a single, general term masks the tremendous complexity of the processes involved. Successful formulations of S have been accomplished only for a very few processes such as adsorption, cation exchange, and gypsum dissolution (McWhorter et al. 1979, Glas et al, 1979, Freeze and Cherry 1979).

Sedimentology

No discussion of water quality related to surface mining would be complete without a treatment of erosion and sedimentation. These processes are no less complicated than others that have been presented previously. Again it is necessary to limit the presentation to a few salient features.

The overall erosion and sedimentation process is comprised of several subprocesses. Erosion refers to the combined processes of particle detachment and transport. Particles are detached by raindrop imact and the shear force caused by flow. Downslope movement of sediment will occur only to the extent that the flow is capable of transporting the detached particles. Only minor downslope transport is attributable to raindrop splash. Deposition (or sedimentation) occurs when the entrained sediment load exceeds the transport capacity. The transport capacity is determined by the sediment properties and the flow rate over the surface. Microtopography causes surface runoff to concentrate and form rills. Rills are small-scale channels in which the dominant detachment mechanism is shear force. Water and sediment are contributed to rills from inter-rill areas where the flow is sheet flow and the dominant detachment mechanism is raindrop impact. Erosion rates are influenced by soil particle-size distribution, infiltration capacity, rainfall intensity, soil particle cohesion, slope of surface, length of slope, shape of surface (convex, concave, planar), and soil cover.

As is the case for all other major hydrologic processes, erosion models vary from basically empirical formulations to those based on detailed descriptions of the physical processes involved. For the purposes of this paper, models which seek to predict erosion from essentially empirical formulations will be called models of gross erosion. Simulation models will refer to formulations based on physical principles.

Models for Gross Erosion

A familiar and widely used model in this category is the Universal Soil Loss Equation given by:

$$A = R\,K(LS)CP, \tag{25}$$

where A = soil loss per unit area,
R = rainfall factor,
K = soil erodibility factor,
LS = dimensionless slope-length factor,
C = dimensionless cover factor, and
P = dimensionless conservation practice factor.

The rainfall factor R is an attempt to include the influence of rainfall energy in the predictive equation. Ultimately, R is related to storm intensity. Average annual and monthly values of R can be obtained from charts and tables prepared by various authors and summarized by Haan and Barfield (1978).

The soil erodibility factor K is included to account for a soils resistance to detachment by raindrop impact and flow. Values for K can be estimated from charts and tables summarized in the above reference. These methods for predicting K attempt to account for the effects of infiltration capacity and cohesion of the soil but have not been altogether successful. The length-slope factor LS can be calculated from a knowledge of the length of slope and the slope angle. Irregular slopes can also be treated. The factors C and P are usually treated as one factor. Again Haan and Barfield summarized methods for estimating CP. These authors discussed Equation 25 in the context of surface mining applications; see their reference for additional details on this subject.

Another erosion model that is classified as one for gross erosion is the Modified Universal Soil Loss Equation, given by:

$$Y = 95\ (Qq_p)^{0.56} K\ LS\ CP, \tag{26}$$

where Y = sediment yield in tons per storm,
Q = volume of storm runoff in acre-feet,
q_p = peak discharge in cubic feet per second,

and other factors are as defined for Equation 25. Equation 26 is an event-based model and makes use of the total volume of rainfall excess and peak discharge in place of the rainfall factor. While remaining basically an empirical model, Equation 26 offers distinct advantages in that the erosion is expressed in terms of variables commonly computed in surface water models. The coupling of surface runoff and erosion models is especially simple in this case.

Simulation of Erosion

Simulation models, as the term is used herein, calculate the sediment discharge from a differential equation formulated by combining the mass conservation principle with appropriate constitutive relations. The conservation equation for erosion can be written as:

$$\frac{\partial G}{\partial x} = -\frac{\partial W}{\partial t} + D_i + D_r, \tag{27}$$

where G = sediment discharge (weight per unit time per unit of slope width),
W = weight of sediment in the water per unit area,
D_i = rate of detachment on the interrill areas (weight per unit time per unit area), and
D_r = rate of detachment in rills (weight per unit time per unit area).

The control area for which Equation 27 is written is a strip of width dx measured down the slope and of unit length measured across the slope. Even though rill and inter-rill detachment occurs on different areas within the control area, the detachment rates in Equation 27 are expressed as average rates over the entire control area. The sediment discharge in Equation 27 is the total sediment. Some workers have written the conservation equation for specific portions of the total sediment load (e.g., the wash load and the bedload, Li (1974); others (e.g., Foster and Meyer 1975) assume that W is constant so that the divergence of G becomes equal to the sum of the detachment rates. The detachment rates in Equation 27 can be negative, in which case, they represent depositon rates.

The next step in formulating the model is to introduce expressions for the detachment rates and transport capacity. At this point, workers have taken a wide variety of approaches. A commonly used approach for detachment by flow is to calculate the tractive force (shear force at the surface) and relate the detachment rate to this quantity. The detachment rate due to raindrop impact is often related to rainfall intensity through emirical correlations. Transport capacities are usually expressed as a function of flow rate. Once these relations have been defined, the next step is to combine them with Equation 27 to yield a differential equation for sediment discharge. When the relations selected are sufficiently simple, closed-form analytic solutions are possible (e.g., Foster and Meyer 1975). Simons et al. (1981) divided the total sediment load into bedload and wash load components. This approach requires that the transport capacity of each component be modeled. These authors relate the bed-load transport to the tractive force on the surface and the wash load transport to the mean velocity. They also relate the raindrop detachment to rainfall intensity.

SPECIFIC MODELS AND APPLICATIONS

In the foregoing sections, I have attempted to provide a general framework in which model development and application can be viewed and understood. The emphasis has been on the processes which operate within each of the major subdivisions of the hydrologic cycle and the linkages among them. A familiarity with these processes provides the basis for understanding the capabilities and applications of specific models to specific problems. The features and applications of several specific models are discussed in subsequent paragraphs. The selection of specific models for discussion was based upon the desire to demonstrate the range of procedures available, known use in mining-related hydrology, and availability in the literature. A great many models and applications exist in proprietory consulting reports that are largely unaccessible. It is important to again emphasize that no single best model for all applications exists. Inclusion or omission of specific models in the following discussion should not be construed as a recommendation for or against any such models.

Even with the rapid development of digital computers and efficient numerical solution techniques, analytic solutions to the equation of ground-water flow remain useful for many purposes. Probably the major constraint on the use of analytic solutions is requiring homogeneous and isotropic aquifer properties. These conditions are rarely approximated except locally near a well or pit. Thus, analytic solutions are rarely useful in regional analyses. A very common and important use of analytic solutions is in determining aquifer properties from aquifer tests. Several procedures by which this may be accomplished have been presented previously. Hydraulic properties obtained in this way are subsequently regarded as existing at a point. The spatial variation of the hydraulic properties can be depicted by contour lines. Rehm et al. (1980) summarized the hydraulic properties of materials related to coal mining in the Northern Great Plains and showed examples of contour lines drawn on hydraulic conductivity data.

Analytic solutions are sometimes useful for calculating inflow to pits. the geometry of the flow problem may be an additional constraint in this application. Van Voast (1974) used an analytic solution that predicts the variable discharge to a well with constant drawdown to estimate flow into the Decker Mine. He treated the mine as a large, variable-diameter well. In recognition of the fact that the analytic solution did not account for the variable aquifer properties, Van Voast emphasized the relationship between drawdown and discharge predicted by this solution. McWhorter (1981, 1982) provided several approximate analytic solutions for ground-water inflow to an advancing pit, inflow to a pit advancing downdip from the crop line and inflow to a pit advancing adjacent to an alluvial valley. These solutions account for both confined and unconfined zones in the flow system and can be used to estimate the extent of the affected piezometric surface. A formula for the steady state drawdown in the presence of induced leakage was also given by McWhorter (1981). Williams et al. (1981) reported the use of analytic techniques for calculating the inflow to mines in the presence of leakage.

Another local situation that is often amenable to use of analytic models is spoil-bank hydraulics (McWhorter 1982). Pearson (1979) used a finite element solution to calculate the water-table configuration and spoil-bank seepage hydrograph. McWhorter's (1982) analytic solution treats the same problem, although more approximately, and is applicable to an arbitrary sequence of recharge events.

As indicated above, simulating ground-water response over large areas requires that the variable hydraulic properties be taken into account. A common method by which it is accomplished is to solve finite difference or finite element equivalents of Equation 8. This involves overlaying the study area by a grid network or mesh and assigning appropriate hydraulic properties to each grid. The solution then gives the values of the variables of interest at each grid or nodal point. The ability to handle variable aquifer properties is achieved at the expense of loss of local information within the grids. In large-scale problems, individual grids may be 1 mile or more on a side.

An example application of the Prickett-Lonnquist (Prickett and Lonnquist 1971) finite difference model to ground-water impacts of mining in the Powder River Basin is given by Koch and McIntosh (1981). The finite difference model is a flexible one, capable of simulating confined and unconfined aquifers, leakage and recharge, and evapotranspiration. Koch and McIntosh discussed the calibration of the model by adjusting the transmissivity and leakage by trial and error until a satisfactory agreement between the measured piezometric surface and the calculated one was achieved. Even though these authors finally used the same transmissivity for all grids, their work demonstrates the power and usefulness of the finite difference model for assessing the regional impact of mining.

Of course, the use of numerical ground-water models is not limited to regional scale problems. Williams *et al*. (1981) reported the use of a finite difference model for calculating piezometric heads and pit inflow for a mine in Wyoming. Quantitative estimates of discharge and recharge from the coal aquifer were derived. Also, estimates of the distance to which the piezometric surface in overburden aquifers will be disturbed and pit inflows were obtained. The author has used the finite difference ground-water model given by McWhorter and Sunada (1977) to comute mine inflows and piezometric surface distributions for a complicated and time-varying mine plan. This model will handle moving boundaries, confined and unconfined flow, leakage, recharge, and pumping under a variety of boundary conditions. A similar model is that of Trescott *et al*. (1976). Bair and Parizek (1981) reported the use of the Trescott *et al*. model to simulate changes in the piezometric surface around an open-pit coal mine.

Runoff and Erosion

The model called SEDIMOT II (Wilson *et al*. 1981) was designed specifically for use in surface mining applications. Rainfall excess is computed by the SCS formula given previously as Equation 16 on subwatershed elements. The rainfall excess is computed on short time intervals from the actual hyetograph or from generalized distributions and routed to the outlet of the subwatershed using unit hydrograph techniques. Generalized unit hydrographs are provided. The hydrographs for each subwatershed are routed down the channels using the Muskingam technique (see Viessman *et al*. 1977). The sediment yield from each subwatershed is calculated from the Modified Universal Soil Loss Equation as expressed in Equation 26. A useful feature of this model is that several sediment control options are built in so that the effects of various control alternatives can be readily analyzed.

An example of a combined runoff and sediment model that uses primarily hydrodynamic methods is that of Simons *et al*. (1981). As with SEDIMOT II, the Simons-Li model is an event-based calculation, but the rainfall excess and channel flow are routed using the kinematic approach (i.e., Equation 20). Also, rainfall excess is computed directly from the rainfall hyetograph and an infiltration function. Again, the real complex watershed is divided into subelements, but this model uses the Wooding plane (open-book) representation for each subelement. This permits direct use of the method of characteristics to solve the kinematic wave equation. Numerical solutions of the kinemative wave equation are used for channel routing. The sediment portion of the model utilizes the mass conservation principle and the fundamental mechanics of the erosion process.

The above models are only two of many that could be included. Jennings et al. (1980) listed 12 models deemed applicable to surface mining hydrology problems. Jennings' tabular summary of these models is reproduced in Table 2. The USGS has under way a program of data collection on 13 mined and unmined watersheds that will be used to test the 12 models listed.

Soil-Water Zone

Any surface runoff model makes use of models in the soil water zone in the sense that infiltration is accounted for in some way. When the emphasis of the effort is on surface runoff, infiltration is usually modeled by one of the formulas discussed previously in this paper. It is not these infiltration models that are dealt with here. The emphasis in this section is on soil-water models that can be used to compute water content distributions and/or drainage below the root zone.

A good example of the use of the Richard's equation (Equation 23) for soil-water zone modeling in mining hydrology is given by Rogowski and Weinrich (1979). These authors use the pressure head form of the Richard's equation and model infiltration and redistribution. They also use the computed drainage below the soil profile as recharge input for the Prickett-Longquist model mentioned previously. By this method they were able to simulate the two-dimensional distribution of water table elevation near a top-soiled strip mine area.

A similar model was developed by McWhorter et al. (1979), who used the water-content form of the Richard's equation and simulated infiltration and redistribution in mine spoil. Their results showed that a unit potential gradient develops at a depth below the active zone of infiltration and redistribution. Below this depth, recharge can be routed to the water table under the gravitational gradient. They compared their model predictions with measured drainage rates from four experimental installations in the field. The drainage below the soil zone was used as recharge input to a finite difference ground-water model.

Much less sophisticated (and often more practical) approaches have been used in mining hydrology. Williams et al. (1981) reported the use of the following equation to assist in estimating deep percolation (drainage) from the soil water zone:

$$W = R\ t^{-b}, \qquad (28)$$

where W = total volume of soil-water per unit area above the bottom of the active root zone
t = time since infiltration event,

TABLE 2. SUMMARY OF MODEL PROCESSES AND CHARACTERISTICS.*

Process and characteristics	Model											
	ARS	ANSWERS	AS	CSU	CREAMS	HYSIM	UK	UT	USDA	USGS	USU	VPI
Streamflow processes	X	X	X	X	X	X	X	X	X	X	X	X
Distributed	X	X	X	X			X		X	X	X	X
Lumped					X	X	X	X				
Water quality transport												
Sediment transport	X	X	X	X	X	X	X	X	X	X		X
Channel	X	X		X	X		X	X	X	X		X
Overland	X	X	X	X	X	X	X	X	X	X		X
Model characteristics												
Time intervals												
Continuous			X			X				X		
Storm	X	X		X	X		X	X	X		X	X
Basin Repr.												
Multiple elements	X	X	X	X	X			X	X	X	X	X
single elements						X	X					

*After Jenning et al. 1980.

Acronymus as follows:
ARS = Agricultural Research Service, ANSWERS = Prude Watershed Planning, AS = Arizona State, CSU = Colorado State University, CREAMS = Soil Conserv. Service, HYSIM = Tennesee Valley Authority Stripmine, UK = University of Kentucky, UT = University of Tennessee, USDA = USDA Sediment Laboratory, Polytechnic Institute (see Jennings et al. 1980 for specific references).

and R and b are parameters. While R and b must be determined empirically, the equation has a basis in physical theory. McWhorter (1982) used a macroscopic soil-water balance to estimate recharge from the soil zone. His calculations were made on a monthly period and utilized long-term mean infiltration volumes estimated from a surface water balance.

Water Quality

Water quality models applicable for surface mining problems are scarce. The conceptual models of Groenewold *et al.* (1980) and Hounslow *et al.* (1979) provide the promise of reliable quantitative models that will account for the appropriate chemical and physical interacions that occur. McWhorter *et al.* (1979) adapted the Dutt *et al.* (1972) model to application in mine spoil. The inorganic chemistry of the Dutt *et al.* model was combined with a model for flow in the soil-water zone based on the Richard's equation. Predictions of major ion distributions and total dissolved solids agreed satisfactorily with values observed in the field experimental facilities in northwesern Colorado. This model does not account, however, for the chemically active pyrite that is thought to be important in the Northern Great Plains region.

A total dissolved solids model was derived by McWhorter *et al.* (1979) by combining a TDS balance with an average annual water balance. This model is basically a mixing model in which waters with different TDS levels and in different quantities are mixed. The model makes no attempt to predict the chemistry of waters within the components considered. It was designed to estimate the effect on receiving waters of spoil water seepage and surface runoff. The equation is:

$$P_t = \frac{KRP_n + P_m}{1+KR}, \qquad (29)$$

where P_t = mean concentration of TDS in total watershed drainage including both direct and subsurface runoff,
P_n = mean concentration of TDS in combined direct and subsurface runoff from the undisturbed portion of the watershed,
P_m = mean concentration of TDS in combined direct and subsurface runoff from the mined portion,
K = the ratio of total drainage per unit area on the undisturbed area to that on the mined land, and
R = the ration of the area of undisturbed land to the area of the mined land.

Equations are also provided for estimating P_n and P_m that account for the relative levels of TDS and flow in overland and spoil seepage runoff. Rowe and McWhorter (1978) used this approach to estimate the salt load contribution of the Edna Mine to Trout Creek in Colorado. McWhorter (1982) provided a method for estimating the model parameters so that it can be used on a predictive basis.

A similar approach was used by Woessner et al. (1979). These investigators used the mixing equations based on a macroscopic mass balance to estimate the potential effects of mining on the quantity and quality of the Tongue River, in the Cheyenne Reservation in southeastern Montana. While such mixing models are unsatisfactory in many respects, in many cases they offer the only feasible predictive technique.

SUMMARY

The scope of professional activities of many people associated with surface mining is too broad to permit in-depth study and familiarization with the details of hydrologic modeling. Often, the responsibilities of these same people require at least a casual acquaintance with the terminology and rationale of models. This paper is intended primarily for such people.

It is hoped that the reader has gained an appreciation for the fact that modeling ranges from conceptual visualization to detailed mathematical descriptions. Presenting material in the format of subelements of the hydrologic system was intented to emphasize that hydrologic models are constructs formed from submodels of fundamental processes. The basic hydrologic principles that underpin the models in common use have been very briefly reviewed. It is expected that some knowledge of the fundamental processes will assist in ascertaining the distinguishing features, suitabilities, and capabilities of the various models that exist. Important aspects of modeling that are not emphasized heavily in this paper are data requirements and acquisition procedures. Models vary tremendously wih respect to data requirements; this is of great importance in the selection of a model for a particular application. As stated previously, the best model is one commensurate with the data available and the financial and technical resources of the user, provided results of suitable reliability will be obtained.

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OVERVIEW OF THE ALLUVIAL VALLEY FLOOR REGULATORY PROGRAM

by

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INTRODUCTION

Under provisions of the Surface Mining Control and Reclamation Act of 1977 (SMCRA), certain types of stream valleys in the Western United States are prohibited from disturbance by coal mining activities. Other types of stream valleys in the West may be mined, but reclamation standards are higher than for other types of mined areas. Both of these types of stream valleys are referred to as alluvial valley floors. The impact of the alluvial valley floor statutory provisions, regulations, and guidelines has been the subject of continuing debate between industry and regulatory agencies. This paper reviews the alluvial valley floor issue, discusses current interpretation of the classification and requirements for study of alluvial valley floors, and reports on the status of current revisions to the regulatory program.

OVERVIEW

In a general sense, alluvial valley floors are those areas in the Western United States which (1) are located in topographic valleys, (2) are underlain by unconsolidated deposits that usually have the landform appearance of flood plains or terraces, (3) have a stream channel, and (4) have an agricultural importance derived from the availability of surface or ground water (Fig. 1). The agricultural activities which take place in these areas include irrigation of hay and pasturelands, irrigation of other crops, or at least some grazing use.

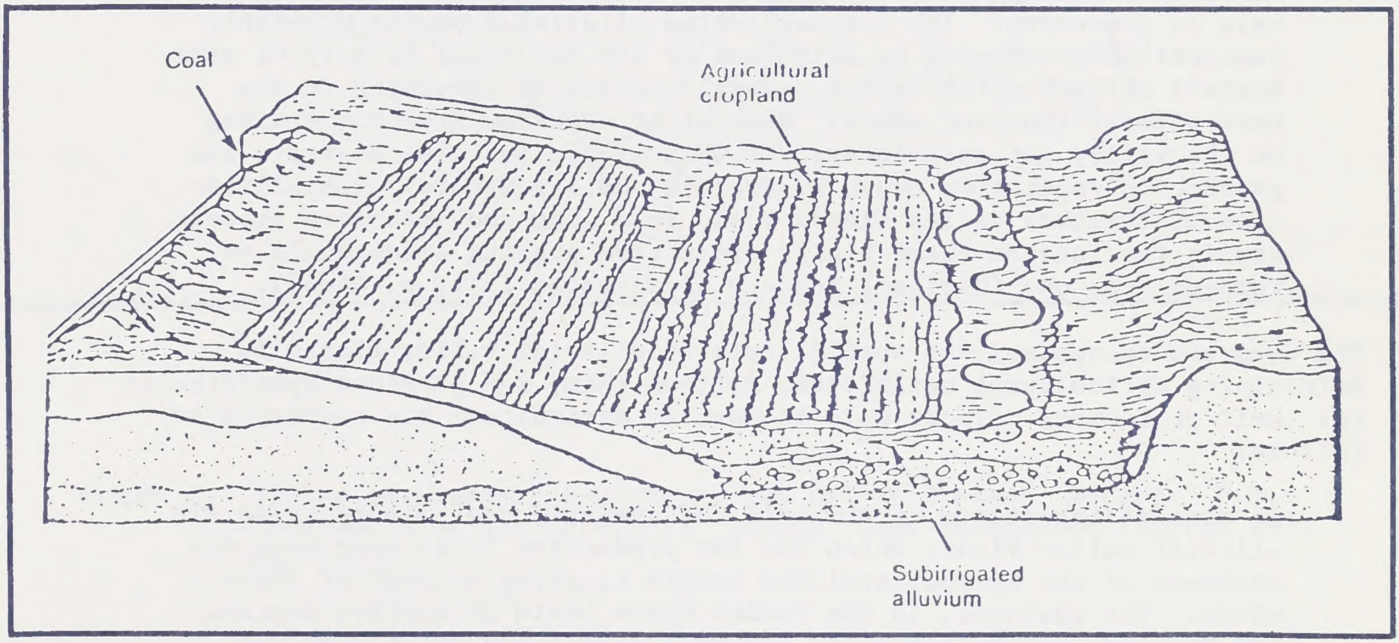

Figure 1. Stylized diagram of an alluvial valley floor. Source: Dollhopf et al. 1979.

From a regional perspective, alluvial valley floors are widespread in the Powder River Coal Basin and are also important in the Fort Union, Green River/Hams Fork, and Uinta coal regions (Fig.2). Limited numbers are found in the San Juan/southern Utah coal region. Generally speaking, alluvial valley floors are associated with almost all perennial streams found in Western coal regions with many intermittent streams and with larger ephemeral streams in the northern coal regions.

Alluvial valley floors are a significant focus of environmental baseline studies and of mining and reclamation plan development. Detailed regulations and guidelines require mining companies to evaluate tracts for the presence of alluvial valley floors and to carefully study the impact of mining on these valleys. For alluvial valley floors designated significant to farming, mining and reclamation plans must demonstrate that material damage will not occur. Any plan for mining and reclamation of any designated alluvial valley floor must demonstrate that "the essential hydrologic functions" of the valley will be restored.

LEGISLATION AND ADMINISTRATIVE HISTORY

The National Academy of Sciences issued a report in 1974 that prompted Congress to consider the effects of surface coal mining on stream valleys in the arid and semiarid portions of the Western United States. It contained the the following statement:

> In the planning of any proposed mining and rehabilitation it is essential to stipulate that alluvial valley floors and stream channels be preserved. The unconsolidated alluvial deposits arehighly susceptible to erosion as evidenced by the erosional history of many western valleys which record several periods of trenching in the past several thousand years. Removal of alluvium from the thalweg of the valley not only lowers the water table but also destroys the protective vegetation cover by draining soil moisture. Rehabilitation of trenched valley floors would be a long and expensive process and in the interim these highly productive grazing areas would be removed from use (National Academy of Sciences 1974, p. 44-45).

The Congress recognized the special role of alluvial valley floors in maintaining agricultural activities, defined them, and provided specifically for their protection. Their role in Western agriculture was expressed as follows:

> Of special importance in the arid and semiarid coal mining areas are alluvial valley floors which are the productive lands that form the backbone of the agricultural and cattle ranching economy of these areas. For instance, in the Powder River basin of eastern Montana and Wyoming, agricultural and ranching operations which form the basis of the existing economic system of the region could not survive without hay production from the naturally subirrigated and flood irrigated meadows located on the alluvial valley floors. (U.S. House of Representatives Committee on Interior and Insular Affairs 1977, House Report 95-218, p. 116).

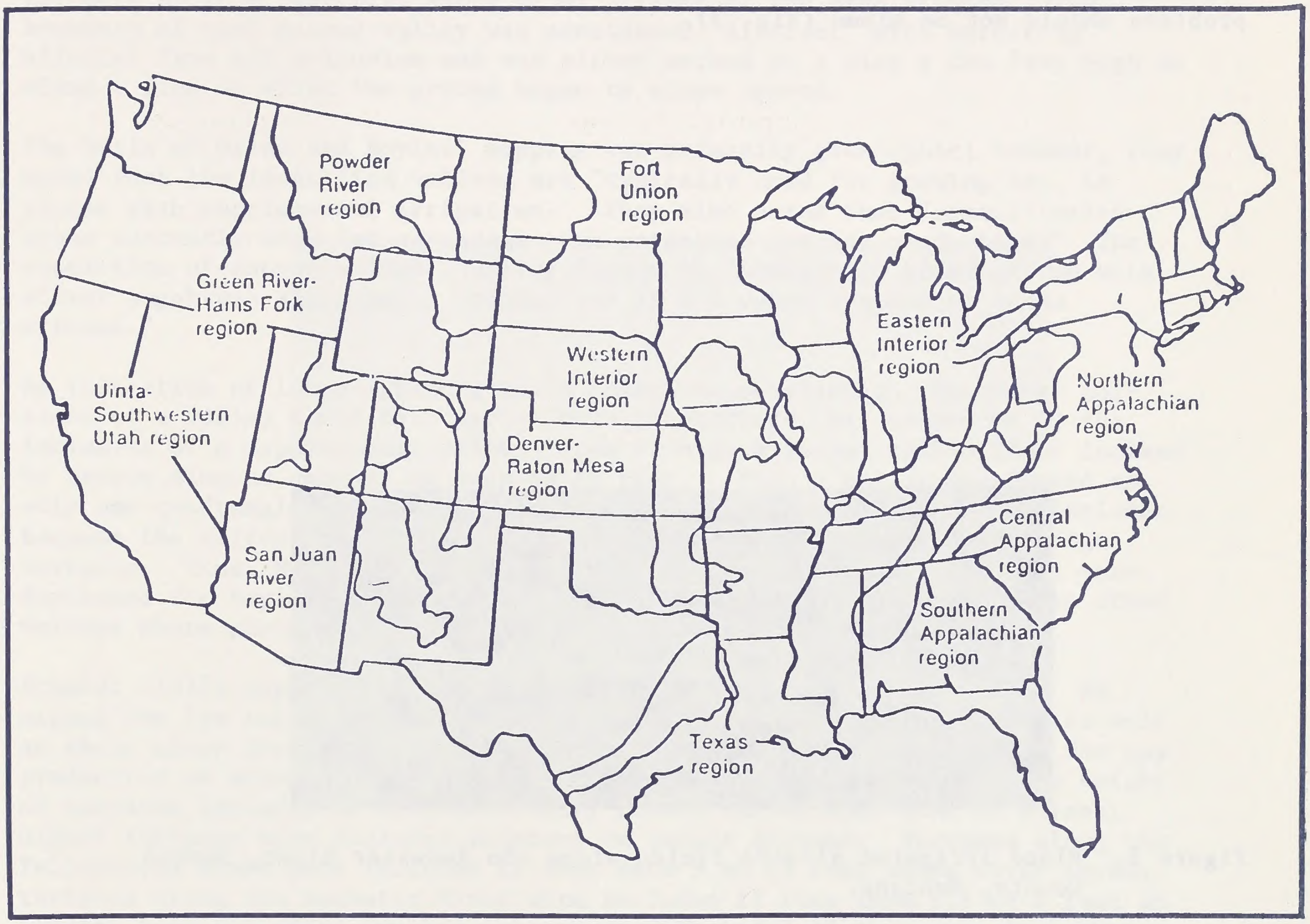

Figure 2. Twelve coal supply regions of the United States. Source: U.S. Department of the Interior: Federal Coal Management Program 1979. (p. 1-4.)

Thus, two concerns were voiced about the surface impacts of coal mining on Western stream valleys: (1) the need for adequate reclamation of valleys composed of unconsolidated fill (poorly planned reclamation would result in the initiation of gullying); and (2) the agricultural importance of some stream valleys. It was argued in several Congresses that valleys of significant agricultural importance that also had recognized reclamation problems should not be mined (Fig. 3).

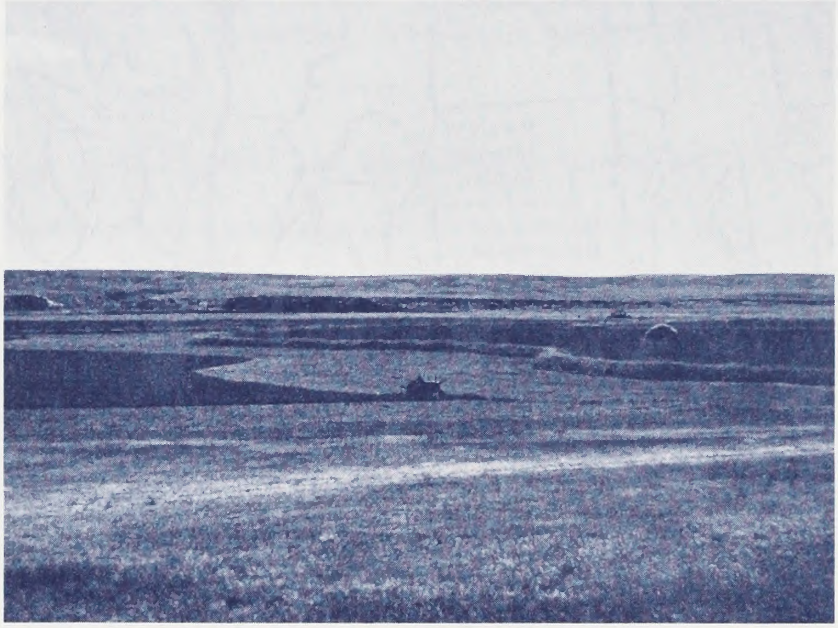

Figure 3. Flood irrigated alfalfa fields along the Redwater River, Dawson County, Montana.

Studies Conducted Prior to Passage of the Surface Mining Act

Prior to passage of SMCRA, three studies had been conducted identifying alluvial valley floors in different parts of the Western United States. The major purpose of each of these studies was to assess the relationship of alluvial valley floors to recoverable coal reserves and to estimate the amount of coal reserves affected by proposed alluvial valley floor provisions. In establishing identification criteria, these studies relied upon draft legislation and Congressional reports of earlier years. Although not precisely consistent with current interpretation of alluvial valley floors (as of 1981), these studies provide some of the few regional data on alluvial valley floor occurrence in the West.

Malde and Boyles (1976) mapped forty-two 7 and 1/2 minute U.S. Geological Survey quadrangles in southeastern Montana for the presence of alluvial valley floors. Their work was the first such mapping effort of its type to be published. The mapping unit for alluvial valley floors included the channel, floodplain, "and low alluvial terrace deposits." These terraces were generally not higher than 5 feet "above the channel floor of small streams," but were up to 8 feet high along major streams of the area studied. The boundary of each mapped valley was considered "distinct" with bordering alluvial fans and colluvium and was either marked at a step a few feet high or along a line at which the ground began to slope upward.

The basis of Malde and Boyles' mapping was primarily geomorphic; however, they noted that the identified valleys are "typically used for growing hay, in places with supplemental irrigation." They also noted that "noncultivated areas currently used for pasturage have potential for hay production." The vegetation of mapped alluvial valley floors is "dominantly grass, mixed with silver sagebrush along small streams and in the upper reaches of large streams."

An indication of inconsistency, or at least the observation that other portions of a valley could have agricultural importance, was evidenced by the inclusion of a mapping unit called "area of high alluvial valley floor incised by narrow sinuous channel as deep as 12 feet." Such a valley was mapped on only one quadrangle, however. This particular valley was apparently included because the valley floor in question included developed hayfields on high terraces. Thus, Malde and Boyles recognized that some incised valleys were developed for hayland but they did not extrapolate their observation to other valleys where similar situations existed.

Schmidt (1977) mapped alluvial valley floors in east-central Montana. He mapped the low terraces, floodplains, and channels of major drainages as well as those minor drainages "whose low terraces were either used in part for hay production or which appeared to have the potential for such use." The height of terraces included as alluvial valley floors varied with size of stream; higher terraces were included adjacent to larger streams. Terraces along the Yellowstone River were included if they were 9 to 12 feet above river level; terraces along the Redwater River were included if they were 6.5 to 9 feet in height; terraces along smaller streams were included if they were less than 6.5 feet above the channel bed; and terraces along the smallest mapped stream valleys were included if they were within 4.5 feet above the channel bed.

Schmidt noted that "deeply incised valleys, terraces without vigorous vegetative growth and valleys with extensive surfaces covered by gravel were not mapped as alluvial valley floors." Similar to Malde and Boyles, Schmidt mapped only the lower terraces in situations where multiple terraces were observed. Contrary to Malde and Boyles, Schmidt did not find a relationship between silver sagebrush occurrence and alluvial valley floors. After reviewing soils and agricultural data, Schmidt found that "valley floors in these study areas are most important as forage producers and secondarily as sites of hay production." In fact, Schmidt estimated that about 75% of the mapped valleys were not in hay production. However, he did consider that mapped alluvial valleys had the potential for hay production or were at least important to grazing activities.

Hardaway et al. (1977) mapped alluvial valley floors on Federal leaseblocks throughout the West. The Hardaway report was based primarily on interpretation of aerial photographs and not on field investigation. Criteria used for designation of alluvial valley floors were if: (1) the area was underlain by alluvial deposits or had surface landforms of flood plains and terraces, (2) the area exhibited more vigorous vegetative growth than surrounding areas, thus indicating subirrigation, and (3) the valley was wider than 45 feet. Lowland areas generally higher than 4.5 feet above minor streams or more than 7 feet above major streams were not considered to be alluvial valley floors, because they were considered to be too high for subirrigation. Although presence of hayed lands in valleys was considered confirmation of alluvial valley floor status, it was not a necessary attribute of the areas. Little assessment was made of alluvial valley floors based on their flood irrigation capability.

Obviously, the criteria used in these three regional studies conducted prior to passage of SMCRA were not entirely similar. Each study attempted to use geomorphic criteria to delineate subirrigated agriculturally important areas. Some studies also attempted to delineate irrigable areas, although only low-terrace sites were considered irrigable. Terraces above the lowest level were not mapped, even if irrigated by ditch systems. Each investigator interpreted the then-proposed alluvial valley floor provisions as not considering large-scale ditch irrigation systems. The studies by Malde and Boyles and by Schmidt recognized that some moderate to high terraces had agricultural importance. These areas were noted but not designated as alluvial valley floors.

Each investigator also placed substantial emphasis on the likelihood of subirrigation on alluvial valley floors. Terraces were mapped as alluvial valley floors if they were within certain heights of the adjacent stream channel. The amount of incision of a channel into the valley flat was considered indicative of whether or not subirrigation occurred.

These early regional studies conducted prior to the passage to SMCRA provide some insight into the geographic extent of alluvial valley floors. They do not, however, precisely describe the extent of any alluvial valley floor according to the definition given in SMCRA and interpreted by regulatory agencies. The main differences between identifications made in the reconnaissance studies and those subsequently made by regulatory agencies are:

1. Large-scale ditch irrigation systems are now sometimes used to establish alluvial valley floor status.

2. Less attention is currently placed on the capability of an area to be subirrigated, although this issue is not resolved. See the last section of this paper, "Status and Problems of the Current Regulatory Program."

3. The reconnaissance studies did not identify areas with the capability to be flood irrigated, based on regional water use patterns.

Surface Mining Control and Reclamation Act (SMCRA) of 1977

The Surface Mining Control and Reclamation Act (SMCRA) passed by Congress in 1977 was the first national law to mandate that reclamation be conducted at all surface coal mines and on the surface of underground coal mines. The statute has particularly strong provisions concerning the protection of hydrologic resources and alluvial valley floors in the Western United States, where adequate water supplies are critical to agriculture. SMCRA authorized a Federal regulatory agency, the U.S. Office of Surface Mining, to promulgate regulations pursuant to the Act, to ensure compliance with the Act and regulations, and to oversee the transfer of primary regulatory control from the Federal government to individual States.

Provisions of SMCRA which apply to alluvial valley floors are found in two sections:

(1) Section 510(b)(5) requires that an applicant for a mine permit affirmatively demonstrate that the proposed operation will not interrupt, discontinue, or preclude farming on alluvial valley floors (with two exceptions), and that the proposed operation will not materially damage the water supply of those alluvial valley floors not excepted.

(2) Section 515(b)(10)(F) requires the preservation of the hydrologic functions of all alluvial valley floors outside the mine area and the reclamation of all alluvial valley floors disturbed by mining.

Regulations

To implement the requirements of the Act, the U.S. Department of the Interior created the Office of Surface Mining and Enforcement (OSM) and developed regulations. Administrative and technical issues related to alluvial valley floors have been dealt with by OSM headquarters in Washington, D.C., and the Western Regional Office in Denver. Draft regulations were subject to normal review and were issued in final form on March 13, 1979.

Generally, requirements for permits for surface coal mining and reclamation operations located on or adjacent to alluvial valley floors in the arid or semiarid West are included in 30 CFR 785.19. Special performance standards for operations involving alluvial valley floors are included in 30 CFR 822. Definitions of some terms important to these regulations are included in 30 CFR 701.5. The regulations also address the surface effects of underground mining on alluvial valley floors. Discussion on the following pages summarizes these regulations.

The Act established that each State would be given primary authority in regulating coal mining operations once the regulatory program of the individual State was determined to be equivalent to or more stringent than the Federal regulatory program. All the Western States having alluvial valley floors have received recognition from the OSM for their permanent regulatory programs. Each State has its own alluvial valley floor regulations, modeled after the Federal regulations; none differs substantially from the Federal regulations. Further discussion of regulations in this paper references the Federal program.

Prior to applying for a permit, all applicants must either acknowledge the presence of an alluvial valley floor within the proposed permit area or adjacent area or submit to the regulatory authority the results of a field investigation of sufficient detail to enable the regulatory authority to evaluate whether or not alluvial valley floors exist in the area.

Applications for proposed mines which may affect alluvial valley floors must contain detailed surveys and baseline data such that the regulatory authority can make the various required findings concerning the alluvial valley floors. These studies and findings then form the basis for approval or denial of the application.

Environmental monitoring is required during the course of mining and reclamation operations. If the operation is causing adverse impacts to farming operations or to the hydrologic systems of an alluvial valley floor, then the mine must cease operations until remedial measures are taken. The monitoring is also used to demonstrate that reclamation of alluvial valley floors has attained the standards required by the Act and regulations.

ASPECTS OF REGULATORY PROGRAM

Definition of Alluvial Valley Floor

The Act defines alluvial valley floors as the unconsolidated streamlaid deposits holding streams where water availability is sufficient for subirrigation or flood irrigation agricultural activities. Specifically excluded are upland areas generally overlain by a thin veneer of colluvial deposits. Existing regulations develop this definition more extensively by defining "unconsolidated streamlaid deposits holding streams," "subirrigation," "flood irrigation," and "agricultural activities."

The term "unconsolidated streamlaid deposits holding streams" is defined not by the actual type of deposit found under the valley floor but by the existence of surface landforms formed during the deposition of unconsolidated streamlaid deposits. The definition thus relies on geomorphology and not the genesis of valley floor deposits. Specifically, all flood plains and terraces located in the lower portions of topographic valleys which contain streams with channels greater than 3 feet in bankful width and greater than 0.5 feet in bankful depth are defined as unconsolidated streamlaid deposits holding streams. Administrative decisions have expanded this definition to include valley fill deposits overlain by slope wash, which are integrally related to areas with terrace or flood-plain landforms.

The term "subirrigation" is loosely defined as the supplying of water to plants from a saturated or semisaturated zone. "Flood irrigation" is defined as the supplying of water to plants by natural overflow or the diversion of flows so that the irrigated surface is largely covered by a sheet of water.

"Agricultural activities" is broadly defined as the use of any tract of land for the production of animal or vegetable life where the use is enhanced or facilitated by subirrigation or flood irrigation. These uses include pasturing, grazing, and watering livestock and cropping, cultivating, or harvesting plants. All uses must benefit from the availability of water from flood irrigation or subirrigation.

In summary, an alluvial valley floor is defined by the existence of flood plains and terraces, the availability of water by flood irrigation or subirrigation, and the use or potential use of that water and land for agricultural purposes.

Statutory Protection of Alluvial Valley Floors

The provisions of SMCRA specifically prohibit mining of certain alluvial valley floors, include stringent reclamation standards for those alluvial valley floors not prohibited, and require that mining not materially damage the hydrologic functions of offsite alluvial valley floors which would otherwise be prohibited from mining. As with the definition of alluvial valley floors, these statutory provisions are more completely defined in regulations.

The prohibitions to mining an alluvial valley floor are outlined in Section 510(b)(5) of the Act. This section generally states that no coal mining operation may "interrupt, discontinue, or preclude farming" on alluvial valley floors. "Interrupt" and "discontinue" mean that mining cannot disturb any portion of an alluvial valley floor where flood-irrigated or subirrigated agricultural activities occur, except for specific alluvial valley floor areas excluded by the Act.

Two types of alluvial valley floor areas are exempt from the prohibition of mining language of the Act. The first exemption is given to undeveloped rangelands not significant to farming and to lands of such small acreage that their mining would have negligible impact on the farm's production. The second exemption is for lands identified in approved reclamation plans from which coal was produced in commercial quantities or for which permit approval was obtained in the year preceding the passage of SMCRA.

Section 510(b)(5)(B) also protects the hydrologic systems associated with the alluvial valley floors preserved from mining. A mining operation cannot materially reduce the quantity or quality of water in surface or groundwater systems which supply the valley floors. Therefore, it is possible that additional areas not designated as significant alluvial valley floors might be excluded from mining if adequate mitigation measures could not be taken to eliminate the adverse impacts. Furthermore, Section 515(b)(10)F) requires that the essential hydrologic functions of alluvial valley floors be preserved throughout the mining and reclamation process. This section mandates that all offsite alluvial valley floors be protected during mining and reclamation.

Section 515(b)(10(F) also establishes the reclamation standards for alluvial valley floors not excluded from mining under the provisions of Section 510(b)(5). Under the reclamation standards, a coal mine must minimize the disturbances to the prevailing hydrologic balance by preserving the hydrologic functions. In other words, after mining, the reclamation of the alluvial valley floor must include the restoration of the pre-existing hydrologic functions. This requirement to preserve hydrologic functions both during and after mining is unique to alluvial valley floors.

Essential Hydrologic Functions

The Federal regulations expand the concept of protecting the hydrologic systems associated with alluvial valley floors by requiring that these systems and their functions be defined by the applicant. Such definition is essential in determining whether hydrologic functions will be disturbed by an adjacent mining operation or whether the functions can be restored after mining. Similarly, the hydrology of the surrounding area must be understood so that the full effects of the disturbance can be assessed on adjacent areas.

The following essential hydrologic functions of an alluvial valley floor must be evaluated in a permit application (not all alluvial valley floors have all of these functions):

1. Characteristics supporting the function of collecting water, such as the amount and rate of runoff; the relief, slope, and density of the network of drainage channels; the infiltration, permeability, porosity, and transmissivity of unconsolidated deposits of the valley floor; and other factors that affect the interchange of water between surface streams and groundwater systems, including the depth to groundwater, the direction of groundwater flow, the extent to which the stream and associated alluvial groundwater aquifers provide recharge to, or are recharged by, bedrock aquifers.
2. Characteristics supporting the function of storing water, such as surface roughness, slope, and vegetation of the channel, flood plain, and low terraces that retard the flow of surface waters; porosity, permeability, water-holding capacity, saturated thickness and volume of aquifers associated with streams, including alluvial aquifers, perched aquifers, and other water-bearing zones found beneath valley floors; and moisture held in soils within the alluvial valley floor, and the physical and chemical properties of the subsoil that provide for sustained vegetation growth during extended periods of low precipitation.

3. Characteristics supporting the function of regulating the flow of water, such as the geometry and physical character of the valley, expressed in terms of the longitudinal profile and slope of the valley and the channel, the sinuosity of the channel, the morphology of the channels, flood plains and low terraces, the nature and stability of the streambanks and flood plains; the frequency and duration of surface flows of representative magnitude including low flows and floods; and the nature of interchange of water between streams, their associated alluvial aquifers and any bedrock aquifers as shown by the rate and amount of water supplied by the stream to associated alluvial and bedrock aquifers (i.e., recharge) and by the rates and amounts of water supplied by aquifers to the stream (i.e., baseflow).

4. Characteristics which make water available, such as the presence of landforms including flood plains and terraces suitable for agricultural activities.

Condensed from 30 CFR 785.19(d)

Material Damage

Section 510(b)(5)(B) of the Act requires that a mining operation not materially damage the waters of an alluvial valley floor. The phrase "materially damage the quantity or quality of waters which supply alluvial valley floors" is defined in the regulations as changes that significantly and adversely affect the composition, diversity, or productivity of vegetation dependent on subirrigation or that would limit the adequacy of the water for flood irrigation.

Criteria used to determine whether material damage will occur include the following:

1. Potential increases in the concentration of total dissolved solids of waters supplied to an alluvial valley floor, to levels . . . above the threshold value at which crop yields decrease . . . (see Maas and Hoffman 1977).

2. Potential increases in the average depth to water-saturated zones (during the growing season) located within the root zone . . . that would reduce the amount of subirrigation land compared to premining conditions.

3. Potential decreases in surface flows that would reduce the amount of irrigable land compared to premining conditions.

4. Potential changes in the surface or groundwater systems that would reduce the area available to agriculture as a result of flooding or increased saturation of the root zone.

(30 CFR 785.19(e)(3)

U.S. District Court Review of Permanent Regulations

Following adoption of the final Federal regulations, the Peabody Coal Company and several States sued the Federal government on numerous aspects of the regulations. The decision by the United States District Court for the District of Columbia Civil Action No. 79-1144, known as the Flannery Decision, sheds light on several aspects of the alluvial valley floor regulatory program. The Court sustained the U.S. Office of Surface Mining (OSM) interpretation that alluvial valley floors may be found along perennial, intermittent, or ephemeral streams. The Court noted:

> An alluvial valley floor must satisfy geologic criteria (unconsolidated stream-laid deposits meeting the regulation's dimensions) and hydrologic criteria (water sufficient to sustain agriculture). Hence, those ephemeral or dry streams incapable of supporting agriculture by natural or artificial means fail to qualify as an alluvial valley floor. . . .
>
> The Senatorial exchange (between Senators Bartlett and Metcalf) . . . demonstrates that dry water streams without surface or subirrigation capability are excluded from the definition of an alluvial valley floor, whereas dry water streams with irrigation capability are subject to the Act's protections. The key is water availability. Congress' concern was the preservation of agriculture. This concern is protected whether the alluvial valley floor contains natural subsurface irrigation or is capable of irrigation by surface means.
>
> (p. 47-48)

Thus, the Court emphasized the basis of an alluvial valley floor as containing both geomorphic and water availability attributes, which together have agricultural importance.

The regulatory requirements to collect detailed sets of geologic, hydrologic, soils, vegetation, and agricultural data were also upheld by the Court:

> The informational requirements of 30CFR 785.19 are consonant with the Act. . . . The Act thus commands an operator, who seeks to mine coal in or around an alluvial valley floor, to provide additional information in the permit application specific to the values underlying alluvial valley floor preservation. The regulations at issue merely implement these informational requirements.
>
> As to the agricultural informaiton of Section 510(b)(5), if an alluvial valley floor fails to encompass agricultural activities, then the permit application need only present rudimentary evidence of lack of farming. . . . However, hydrologic information must still be provided. If the permit area encompasses an alluvial valley floor, the hydrologic protections of Sections 510(b)(3) and 515(b)(10)(F) apply regardless of whether farming occurs.
>
> (p. 49-50)

The Court mandated minor changes, such as remanding the requirement that a full year's hydrologic data be collected, but basically upheld the notion that alluvial valley floors require detailed study.

Guidelines and Review of Identification Procedures

Guidelines for identifying alluvial valley floors, as well as their hydrologic and agricultural characteristics, have been developed in draft (8/25/79) and final (6/11/80) form by the OSM as well as by the State of Wyoming. The Federal guidelines are designed to facilitate alluvial valley floor identification in all coal-producing geographic regions of the Western States.

These guidelines provide a procedure for identifying and then studying alluvial valley floors, as well as a suggested evaluation process in which progressively more detailed information is obtained. Initially, regional data are used to identify probable alluvial valley floors. Then, detailed, site-specific data are obtained only for areas of probable concern.

The OSM's alluvial valley floor guidelines thus consist of three parts:

1. Reconnaissance investigation procedures for identifying probable alluvial valley floors and identifying lands clearly not alluvial valley floors.

2. Guidelines for intermediate study of potential alluvial valley floors leading to final designation.

3. Guidelines for detailed studies necessary for submitting a complete application for a permit area or adjacent area which includes an alluvial valley floor.

Because of the variation among regions and specific sites, it is difficult to develop quantitative criteria for every important characteristic of alluvial valley floors. In many cases, determinations still involve judgments by experienced personnel. Both the Federal and State guidelines encourage that good contact be maintained between industry and regulatory agencies to ensure prompt and efficient study and decisionmaking.

Reconnaissance Investigation Procedures

The reconnaissance procedures involve determining areas which meet both the geomorphic and water availability characteristics in the permit area and adjacent areas but do not involve collecting detailed site-specific data. The purpose is twofold: To determine if certain areas clearly do not contain alluvial valley floors, thus allowing the applicant to dispense with any further study; and to identify areas which probably do contain alluvial valley floors. If data are insufficient to confirm that alluvial valley floors do not exist, more detailed studies usually are necessary.

The current or historic existence of flood irrigation or the capability of lands to be flood irrigated are evaluated through the use and extrapolation of land use data. Lands currently or historically flood irrigated can be identified from aerial photographs, field reconnaissance and existing land use inventories. To evaluate flood irrigation capability, the pattern of flood irrigation in the region surrounding the permit area is evaluated. Watersheds of similar physiographic, agricultural, geologic, climatic, hydrologic, soils, and vegetation characteristics are identified. The region containing these watersheds might include a few counties or an area of several square miles surrounding a permit area. Within this area, all current or historically successful flood irrigation areas are identified. Flood irrigation in valleys with drainage basins similar in size or smaller than those of the proposed mine site can then be evaluated on the ground to determine the height above the channel of irrigated lands, the type of irrigation practiced, and other important site conditions.

Following this regional evaluation, all lands in the surface water-adjacent area or permit area with similar physical conditions would be identified as flood irrigable. For example, if the only flood irrigation practiced in a region occurred along perennial streams on terraces less than 15 feet above the adjacent stream channel, lands in the surface water-adjacent area or permit area along intermittent and ephemeral streams would not be considered flood irrigable. If, on the other hand, flood irrigation was occasionally practiced in the valleys of ephemeral streams with drainage basins greater than 5 square miles, and on terraces less than 10 feet above the adjacent stream channel, then lands in the surface water-adjacent area or permit area of a similar condition could be considered flood irrigable.

A later section of this paper describes a case study using the suggested approach.

Reconnaissance to determine subirrigated areas is done by identifying from aerial photographs and field work, all topographic valley floor lands where agriculturally useful vegetation is dependent on moisture supplied by groundwater or frequent flood flows. These areas can often be distinguished on color infrared photography taken in late summer. At this time of year, upland areas are usually dormant while lowland vegetation may still be growing if water is available. Dollhopf et al. (1979, 1981) provide a good discussion on subirrigation. Lands identified as potentially subirrigated should also be evaluated under the geomorphic characteristics described below.

The lands identified as flood irrigated, flood irrigable, or subirrigated in the study area should also be evaluated in relation to the geomorphic characteristics, since only lands underlain by "unconsolidated streamlaid deposits holding streams" constitute alluvial valley floors.

The surface extent should be determined for all flood plains and terraces underlain by unconsolidated material found in the lower parts of topographic valleys which also have identifiable stream channels (defined in regulations as "channels that are greater than 3 feet in bankful width and greater than 0.5 feet in bankful depth"). In plan view, these terraces and flood plains together with the channel normally would form one contiguous unit with only small inclusions of nonalluvial material such as bedrock outcrops or thin layers of eolian sand or silt. The total extent of these areas should be mapped along valley margins to the point where the essentially flat-lying streamlaid deposits encounter the sloping deposits of the surrounding hillsides.

This procedure should identify all streamlaid deposits associated with an identified stream channel and exclude isolated, higher terraces separated areally from the main valley floor. Terrace deposits along upland drainage divides should not be mapped. In the case of alluvial fans, only land on fans related to the modern stream course should be identified. It is not intended that the entire surface of large fans found typically in basin and range topography be identified.

Once the regional agricultural water use and site geomorphology have been determined, the following criteria can be applied at the reconnaissance level:

1. Valleys are clearly not alluvial valley floors if they do not contain any areas meeting the geomorphic characteristics.

2. Lands meeting the geomorphic characteristics but not identified as flood irrigated, flood irrigable, or subirrigated can be released from further alluvial valley floor study. These lands must not (a) be presently or have ever been flood irrigated, (b) be flood irrigable, and (c) show evidence of subirrigation.

3. Under existing Federal guidelines, all lands which are probable alluvial valley floors should also generally be wider than 50 feet and exceed 10 acres in size.

Intermediate Study Procedures

The intent of the intermediate studies is to supply sufficient information to allow final determination of alluvial valley floors by the regulatory authority. These studies document the geomorphic and water availability characteristics of any lands within the permit area or adjacent area identified in the reconnaissance study as probable alluvial valley floors. In other words, intermediate studies are intended to confirm as alluvial valley floors areas identified in reconnaissance studies. Areas discarded under reconnaissance studies are not generally evaluated under intermediate studies. Specific study components include:

1. Surficial and subsurface geologic mapping at a more detailed scale to identify all flood plain and terrace levels underlain by unconsolidated material;

2. Mapping of all areas which are or have been flood irrigated;

3. Further study to substantiate that irrigation is possible on the lands identified as flood irrigable in the reconnaissance study. The suitability of stream flow, water quality, soils, and topography should be assessed;

4. Field investigation at sites identified as subirrigated in the reconnaissance study to document actual subirrigation.

To qualify as an alluvial valley floor, lands must meet the geomorphic criteria and any one of the three water availability characteristics.

Detailed Study Procedures

OSM guidelines suggest studies which can identify:

1. The characteristics of an alluvial valley floor.

2. The significance to agriculture of an affected alluvial valley floor.

3. The impact of mining on an alluvial valley floor.

4. The effectiveness of proposed reclamation and environmental monitoring.

The regulatory authority is required to make various findings based on these studies and any other information concerning the impact of the proposed mining on alluvial valley floors and the effectiveness of any proposed reclamation.

Generally, alluvial valley floors within the proposed mine area require more study than alluvial valley floors elsewhere in the permit area or in the adjacent area because of the direct disturbance caused by mining and the subsequent need for reclamation and restoration. Alluvial valley floors possessing only flood irrigation characteristics do not require the detailed subsurface investigations required of those that are subirrigated.

The study components outlined in this part of the Federal guidelines are numerous and detailed. Not all are applicable to each mining/alluvial valley floor situation and some are similar to studies required by other sections of SMCRA. The areas of investigation include geology, soils, vegetation, surface water hydrology, geohydrology, water quality, and agriculture. For further detail, the Federal guidelines should be consulted.

REVIEW OF ADMINISTRATIVE ACTIONS

Alluvial valley floors have been identified in five Western States. For the most part, these are either significant valley floors which will not be affected by mining or insignificant valley floors whose hydrologic functions will be preserved during mining. In these situations, studies have documented that adverse impacts will not occur. Only one alluvial valley floor has been banned from mining. One mine plan has been approved in Wyoming which calls for reestablishment of flood irrigation capability, and several mine plans currently under review provide for reestablishment of subirrigated alluvial valley floors.

Due to the variation in mine size and type and in agricultural and hydrologic characteristics of alluvial valley floors throughout the West, administrative actions need to be discussed on a regional basis. The effect of mining on haylands of alluvial valley floors is the primary concern in the Powder River Basin. Underground mining beneath valley floors cultivated for such diverse crops as fruit, sugar beets, and alfalfa is a concern in Colorado. In New Mexico, little agricultural use is made of any but the largest stream valleys.

Powder River Basin

The Montana Department of State Lands, with the concurrence of OSM, has determined that Squirrel Creek Valley in Big Horn County is an alluvial valley floor, portions of which are currently flood and subirrigated. The stream is a perennial tributary of the Tongue River and crosses portions of Federal coal leases held by the Rosebud Coal Sales Company and the Consolidation Coal Company. Areas with significant farming activities total about 250 acres; however, the total alluvial valley floor is more than 500 acres. The significant alluvial valley floor is banned from mining.

The impact of this regulatory decision is uncertain at this time. The Consolidation Coal Company has submitted a mine plan for recovery of coal outside most of the designated alluvial valley floor, and Rosebud Coal Sales Company plans on doing the same. Mining may be permitted in portions of the Squirrel Creek valley if no "material damage" will occur to the significant farming areas.

State regulatory authorities, with the concurrence of OSM, have identified alluvial valley floors which are not considered to be significant to farming at the Buckskin, Rawhide, Eagle Butte, and Coal Creek mines, Wyoming, and the West Decker, Spring Creek, and Rosebud mines in Montana. Examples of typical valley floors are depicted in Figures 4 and 5.

The Coal Creek Mine, operated by the Thunder Basin Coal Company, obtained approval for its mine in early 1979 and hopes to begin coal shipments in 1982. Regulatory authorities originally designated 846 acres of the total proposed mine plan area or about 9% as alluvial valley floors. Later review decreased the designated area. Thunder Basin Coal Company must still demonstrate that the "essential hydrologic functions" of the designated alluvial valley floors will be protected before any additional mining will be approved.

At the other two new mines approved after passage of the Act, Spring Creek and Buckskin, uncertainty about alluvial valley floor status and reclaimability

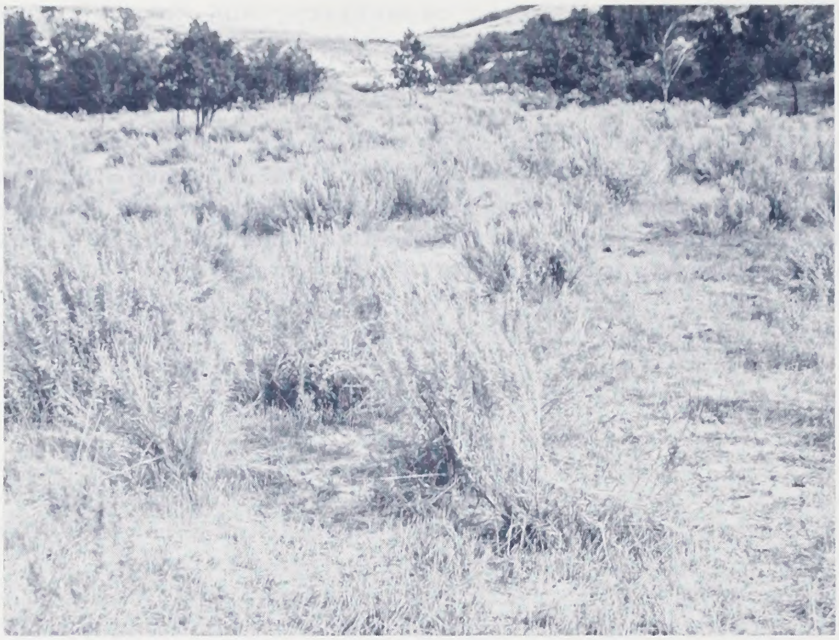

Figure 4. Headwaters of Sullivan Creek, Dawson County, Montana. Silver sagebrush on valley floor may indicate water at depth; however, the valley would not qualify as a subirrigated alluvial valley floor.

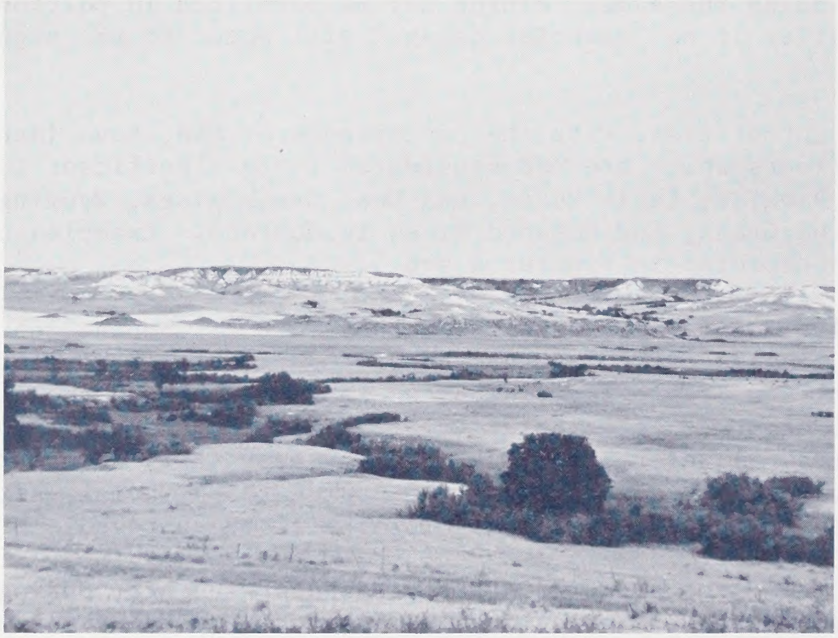

Figure 5. North Fork of Burns Creek, Dawson County, Montana. Narrow lower terrace is subirrigated; broad upper terrace may have capability to be flood irrigated.

has led each operator to avoid proposing the mining of areas of uncertain alluvial valley floor status. Studies are underway in each case to demonstrate that the valleys can be successfully reclaimed.

Several regulatory decisions concerning alluvial valley floors are pending and have affected the orderly development of mine plans. Alluvial valley floor studies are underway with pending decisions at six mines in the Powder River Coal Basin (Table 1). OSM does not anticipate that any of the stream valleys in question will be designated significant to farming and thus be subjected to automatic prohibition from mining. At those mines operating prior to passage of the Act, mine planning has proceeded under the assumption that mining of alluvial valley floors will be approved. Formal regulatory approval, however, has not yet been obtained.

The stance taken by State and Federal regulatory agencies toward compliance with Section 515(b)(10)(F) will have a significant effect on the amount of coal reserves affected by alluvial valley floor provisions. If industry is able to demonstrate that the essential hydrologic functions can be protected during and after mining, then only those floors with significant agricultural activities will be prohibited from mining.

The U.S. Office of Technology Assessment (1981), in evaluating potential alluvial valley floor occurrences on undeveloped leaseblocks throughout the Powder River Coal Basin (Table 2), estimated the area of potential and designated alluvial valley floors to be 3,368 acres. About 7% of the existing Federal undeveloped leaseblock recoverable reserve base is overlain by potential alluvial valley floors. Leaseblocks potentially affected by "significant farming" provisions, and thus possible mining prohibitions, are a subset of those with possible alluvial valley floors. Significant farming areas are likely to exist, however, on a few leases other than the CX leases at Squirrel Creek, Montana, already discussed. Although the potential for affecting additional reserves through inability to develop orderly mine plans might raise the affected reserves somewhat, the increase is not expected to be substantial.

The impact of alluvial valley floor designations and the likelihood of identifying areas significant to farming are of greater concerns to private coal owners in the Powder River Basin than they are to Federal owners. Private coal ownership is often concentrated in major stream valleys where significant farming operations are found. This pattern of ownership exists because the earliest homesteaded lands in the West included mineral as well as surface ownership upon compliance with the homestead standards. The earliest settlers were attracted to the valleys with perennial streams. Thus, the major stream valleys, with the longest history of agricultural use, are generally owned by private entities which also own the underlying coal reserves. Only later did the Federal government begin the practice of transferring surface ownership without transferring mineral ownership. For example, the proposed Montco Mine north of Birney, Montana, and the Peter Kiewit Sons Whitney Benefits Mine north of Sheridan, Wyoming, both on or near the Tongue River, face substantial issues related to farming activities on alluvial valley floors. In the case of the Whitney Benefits Mine, these concerns were substantial enough that no mine plan was submitted to the Wyoming regulatory authority for approval.

TABLE 1. ALLUVIAL VALLEY FLOOR SUMMARY TABLE, DEVELOPED FEDERAL MINES, POWDER RIVER BASIN.

Mine	Permitted Area	Stream	Status	Status
Rosebud	6,221	East Fork, Armells Creek	No	-0-
Big Sky	2,351	Emile Coulee	No	-0-
		Miller Coulee	No	-0-
		Lee Coulee[3]	Potential/ uncertain	275[3]
Spring Creek	3,019 (4,466)[2]	Spring Creek	No	-0-
		South Fork, Spring Creek	Yes	290[4] (1592)[5]
West Decker	3,565	Pond Creek	No	-0-
		Pearson Creek	No	-0-
		Spring Creek	No	-0-
East Decker	4,145	Deer Creek	Potential/ uncertain	390
Buckskin	1,467	Spring Draw	Yes	358
		Rawhide Creek	Yes	
Rawhide[1]	7,393	Rawhide Creek	Yes	200 (940)[5]
		Little Rawhide Creek	Yes	
Eagle Butte[1]	4,304	Little Rawhide Creek	Yes	126
		Dry Fork, Powder River	Potential/ likely	10
Wyodak[1]	3,274	Donkey Creek	No	-0-
Caballo	10,040	Tisdale Creek	No	-0-
		North Tisdale Creek	No	-0-
		Gold Mine Draw	Potential/ unlikely	-0-
Belle Ayr[1]	6,918	Caballo Creek	Potential/ likely	365
		Tisdale Creek	Yes	
Caballo Rojo	5,815	--	None	-0-
Cordero	8,232	Belle Fourche River	Potential/ unlikely	-0-
Coal Creek	9,545	Coal Creek	Yes	116
		East Fork, Coal Creek	Yes	350
		Middle Fork, Coal Creek	No	-0-
		Dry Creek tributary	Yes	44

TABLE 1 (continued).

Mine	Permitted Area	Stream	Status	Status
Jacobs Ranch[1]	4,959	Burning Coal Draw	Potential/ unlikely	-0-
		North Prong, Little Thunder Creek	Potential/ unlikely	-0-
Black Thunder	7,660	North Prong, Little Thunder Creek	Potential/ unlikely	-0-
		Little Thunder Creek	Potential/ unlikely	-0-
Dave Johnston	13,026	--	None	-0-

Notes:

[1] "Grandfathered" mines, mining must be approved if essential hydrologic functions of alluvial valley floor can be restored.

[2] Total permit and amendment area.

[3] Not within presently permitted area.

[4] Within presently permitted and proposed amendment areas.

[5] Total area beyond designated alluvial valley floors as well as alluvial valley floors not to be recovered unless floor reclamation approved.

TABLE 2. ALLUVIAL VALLEY FLOOR SUMMARY TABLE, UNDEVELOPED FEDERAL COAL LEASES, POWDER RIVER BASIN

Lease block	Lease block area (acres)	Acres of designated AVF significant to farming	Acres of designated AVF not significant to farming	Acres of stream valley under study as potential AVF	Name of stream
CX Ranch (Consolidated Coal)	674	245	300	--[b]	Squirrel Creek
CX Ranch (Rosebud Coal Sales)	524			--	
Pearl	541	--		40	Little Young's Creek
Armstrong	80	0[a]	0	0	None
Bass	20,701	0	0	200	Clear Creek Powder River Deadman Creek Several tributaries
Arvada	4,366	0	0	750	Powder River Robinson Draw Wild Horse Creek North Prong, Wild Horse Creek
Lake DeSmet	9,417	0	0	10[c]	Boxelder Creek and Tributary
Belco	4,551	0	0	240	Negio and Dry Creek
Wildcat	1,571	--	--	120	Jamison Prong and Soukup Draw
Blue Diamond	40	--	--	0	None
Dry Fork	3,580	--	--	300	Dry Fork, Little Powder River, Prairie Creek

TABLE 2. (continued)

Lease block	Lease block area (acres)	Acres of designated AVF significant to farming	Acres of designated AVF not significant to farming	Acres of stream valley under study as potential AVF	Name of stream
South Rawhide	4,782	--	0	--	None
East Gillette	4,343	--	0	--	None
Federal			--	--	
Gulf (3)	756	--	--	--	None
East Wyodak	2,560	--	--	25	Lee Draw
North Rochelle	2,000	--	--	0	None
Rochelle and North Antelope	9,141	--	--	120	Porcupine Creek and Tributary Holmes Creek West Fork Creek Tributaries
Antelope	4,817	--	480	--	Antelope Creek West Logan Draw Spring Creek
Phillips Creek (1), (2)	4,079	--	--	60	Phillips Creek Dry Fork Cheyenne River
Totals: Federal Lease Acres	78,523	245	780	1,865	

[a] Indicates determination by regulatory agency that no AVFs are along indicated streams.
[b] Indicates no determination made.
[c] There is an estimated 400 million tons of non-Federal coal under a potential alluvial valley floor, (AVF) associated with this lease block.

Adapted from U.S. Office of Technology Assessment (1981).

Alluvial Valley Floor Occurrence in Other States

Alluvial valley floors occur in each of the other Western coal regions (Fig. 2). By definition, alluvial valley floors do not occur in Oklahoma or other areas east of the 100th meridian. They occur only sporadically in other regions. While only Alderin Creek at the Glenharold Mine in North Dakota is being reviewed for alluvial valley floor status in the Fort Union region, studies by Schmidt (1977) and Hardaway et al. (1977) indicate that up to 10% of the reserve base might be affected by alluvial valley floor concerns in this region (Fig. 6). However, the amount of reserves actually expected to be prohibited from mining will be much less, because most valleys in mine areas are not now being actively farmed.

In the Green River/Hams Fork region, alluvial valley floors may occur in the Hams Fork coal field and in northwestern Colorado. Three blocks in the Hams Fork field have potential alluvial valley floors covering less than 200 acres. No alluvial valley floors are expected to be designated in the Rock Springs or Hanna fields.

In central and western Colorado and east-central Utah, underground mining is conducted on varying scales by many operators. The limited surface disturbance caused by mine facility areas usually does not present problems for alluvial valley floors. However, there is considerable concern about the effect of subsidence of mines under alluvial valley floors and of mining coal aquifers which supply water to alluvial valley floors. To date, several underground mines have received approval to mine adjacent to significant alluvial valley floors. In these situations it has been shown that the mining would not materially damage the hydrology. Several mines currently under review and some proposed mine expansions may seriously affect alluvial valley floors; in these situations, mine plans may have to be altered to avoid the adverse impacts on agriculture and hydrology.

Large-scale strip mining has been proposed for the Alton coal field in southern Utah. Alluvial valley floor determinations may affect mine development in this area (see the following section).

New Mexico has conducted a reconnaissance inventory to identify alluvial valley floors in the San Juan and Raton basins (Love and Hawley 1981). Alluvial valley floors are not present in most areas with existing or planned coal mine operations (Fig. 7). Only the valleys of larger perennial streams that head in mountain ranges can be considered alluvial valley floors. Smaller valley floors do not have water available for the enhanced productivity required for alluvial valley floor designation.

RECONNAISSANCE IDENTIFICATION OF ALLUVIAL VALLEY FLOORS: CASE STUDY

As noted in a previous section, reconnaissance procedures are outlined in existing regulations and guidelines. This section presents a case study in

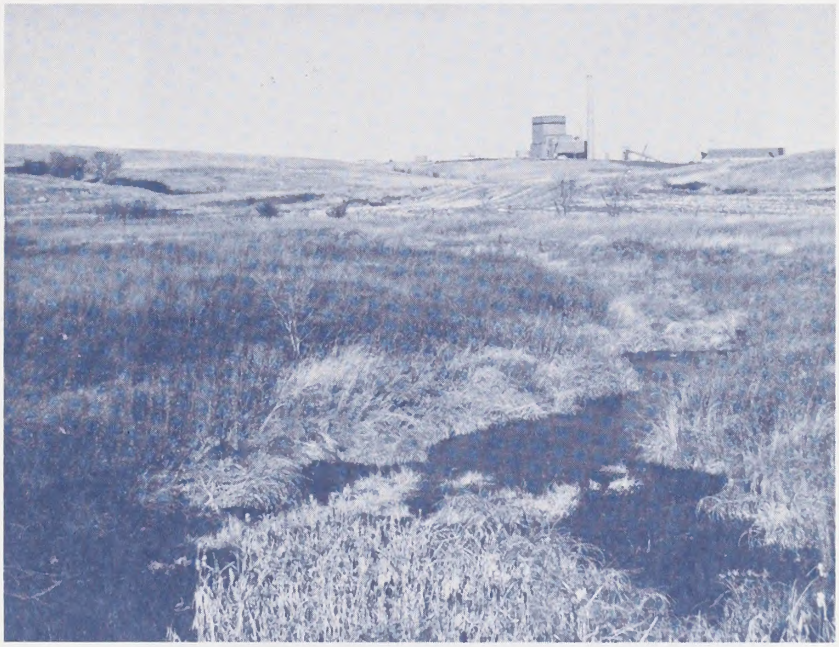

Figure 6. Brush Creek, North Dakota, a tributary to the Knife River and adjacent to proposed mining at a Knife River Coal Mining Company operation. Subirrigation and flood irrigation capability are being studied for an alluvial valley floor designation.

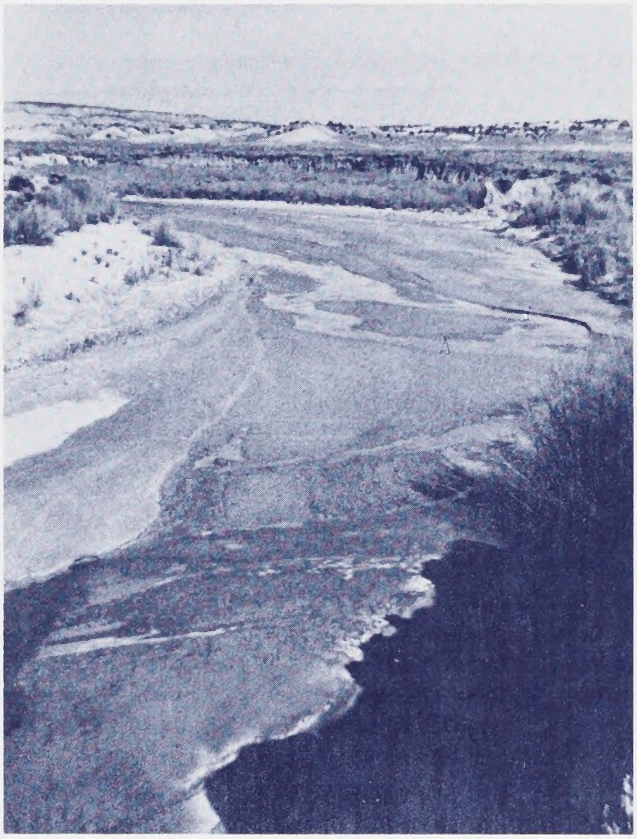

Figure 7. Rio Puerco, tributary to Rio Grande, New Mexico; this large river is not an alluvial valley floor. The incised channel prevents subirrigation of adjacent terraces and the flash flood nature of surface flows is not utilized for diversion and irrigation.

which alluvial valley floors were identified in an area where no previous studies had been conducted--south-central Utah (Schmidt 1980). This study provides a good example of systematic identification of alluvial valley floors in a region where the agricultural importance of valley floors was not initially known.

South-central Utah Case Study

The evaluation of alluvial valley floors in this portion of southern Utah was the first of its type in the Southwest. Some of the notions about alluvial valley floors which have validity in the Powder River Coal Basin do not have application in the Southwest. For instance, agriculture in the Powder River Coal Basin is concentrated along major streams, and the better agricultural land occurs in larger stream valleys. In the Southwest, however, some major stream segments are entrenched in canyons. In many areas, upstream areas have more available water than downstream areas. Integrated drainage systems are less critical to alluvial valley floor evaluation in the Southwest, since available surface and ground water does not increase downstream.

In light of the variable conditions of the Southwest, the evaluation began with the basic notion that an alluvial valley floor is a stream valley whose agricultural importance is derived from the water available in that valley. The first step, therefore, was assessing the agricultural importance of stream valleys and the use of water in those valleys.

Environmental Setting

The area evaluated for the presence of alluvial valley floors was located in Kane County in southern Utah. The area includes the formal Alton unsuitability petition area* as well as those portions of the Kanab Creek and Johnson Wash watersheds north of the Vermillion Cliffs (Fig. 8). This area lies within the Zion Park region of the Colorado Plateau province. The region is dominated by plateaus, cliffs, and canyons, and consists mostly of strongly carved tabular relief. The landscape pattern of the Zion Park region is relatively simple. Rock units gently dipping to the north are expressed as a series of platforms at various altitudes, bordered by great cliffs. The evaluated area consists of four platforms rising to the north from the Kanab Plateau, at about 5,000 feet, to the Paunsagunt Plateau, which rises above 9,500 feet.

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*On November 28, 1979, several national conservation groups, as well as several landowners, filed a petition with OSM to declare an area near Bryce Canyon National Park unsuitable for coal mining.

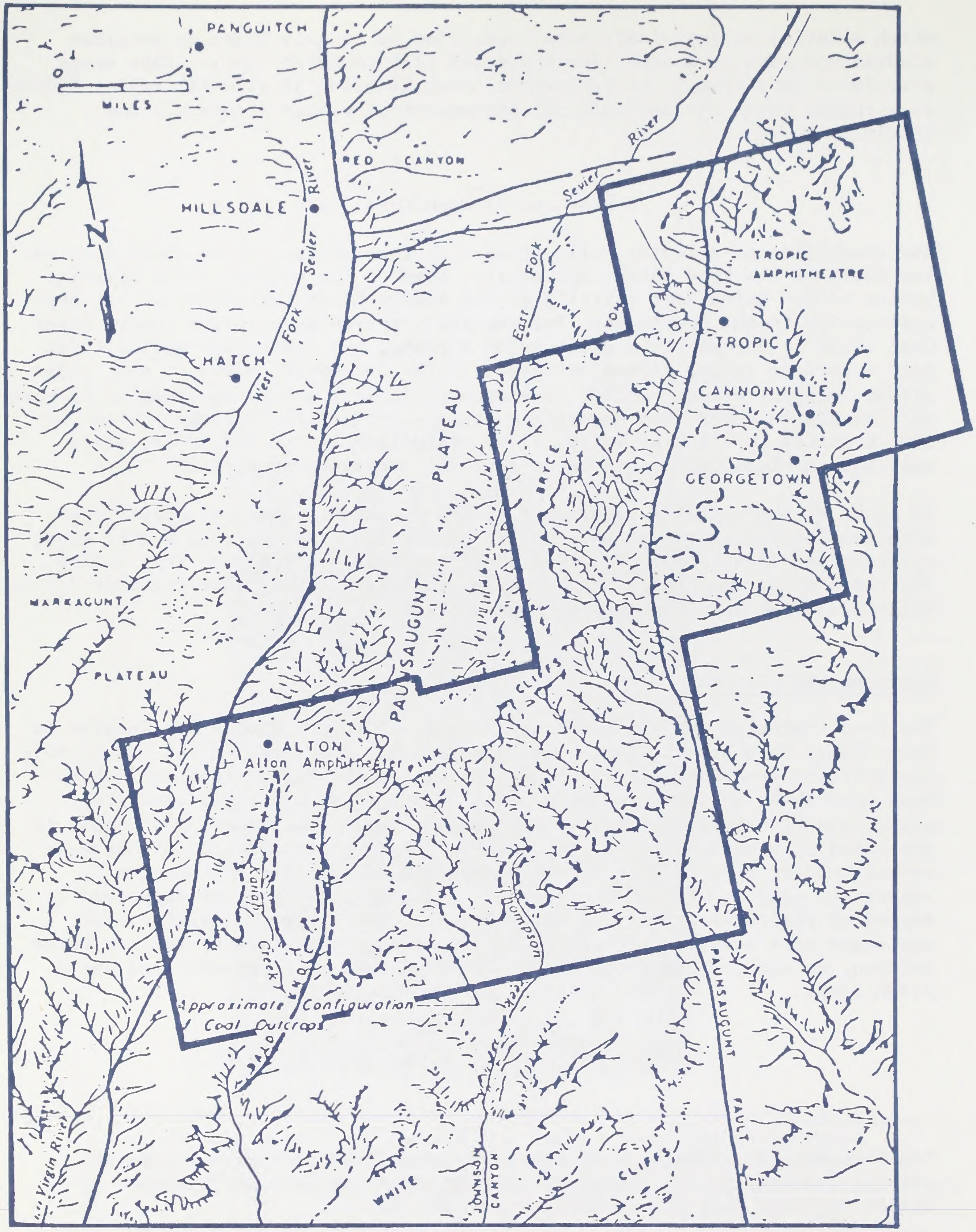


Figure 8. Map of southern Utah petition area showing physiography (U.S. Department of the Interior 1980, Fig. II-A-1).

The climate ranges from arid to semiarid, and cool to warm, depending on elevation. Mean annual precipitation at Alton (elevation 7,000 feet) is 16.4 inches and the average frost-free growing season is 112 days. At Kanab (elevation 4,925 feet), mean annual precipitation is less than 12.5 inches, and the average frost-free growing season exceeds 140 days. The season of least rainfall in the region, April through June, is the major growing season for most crops. Without irrigation, farming is generally not profitable. The source of irrigation water is snow, which falls in greatest amounts at higher elevations. Unlike rainfall, which is often torrential and thus runs off, snow percolates into the soil and supplies the ground-water system and springs. Streams which head in the higher elevations, and which are fed by direct snowmelt or by springs, sustain streamflow at least until June and are diverted for irrigation. These streams are critical to agriculture in the region.

The evaluated area is drained by the headwaters of the East Fork of the Virgin River, Kanab Creek, and the Paria River. Stream segments originating around the Paunsagunt Plateau are perennial in their upper reaches; however, they generally become ephemeral by the time they cross the White Cliffs. Stream segments which head on the Skutumpah Terrace or at lower elevations are ephemeral. Exceptions are those stream segments fed by springs issuing from the Navajo Sandstone.

Valleys are generally entrenched, often as much as 40 feet. Subirrigated meadows are limited and generally located near bedrock springs. The dominant vegetation type of valley flats is sagebrush, and although contributing somewhat more forage than the upland pinyon-juniper vegetation, sagebrush areas are not considered critically productive for grazing land management.

Irrigation is the dominant use of water in the region. All existing stream diversions and irrigated lands were mapped, using data supplied by the Utah State Engineer, the Soil Conservation Service (SCS), Agricultural Stabilization and Conservation Service (ASCS), local ranchers, and field identification. After plotting the diversions and irrigated lands, the regional pattern of irrigation use could be evaluated in light of existing hydrologic and geologic reports. The sources of data used included black-and-white air photos, scale 1:18,500, obtained from the SCS, farm maps obtained from the ASCS, records of water rights filings obtained from the Utah State Engineer, and various geologic and hydrologic reports (Goode 1964 and 1966, Doelling and Graham 1972, Sandberg 1978, Cordova 1980). These data, although not necessaily the most desirable for a reconnaissance evaluation, were all that were available, and were sufficient for such a task. Supplemented by interviews with ranchers and resource professionals, and by fieldwork, a clear picture of agricultural use was developed.

The hydrologic aspects of streams in the Alton area had been described by Goode (1964, 1966), Sandberg (1978), and Cordova (1980). Goode's investigations indicated that perennial or significant intermittent flow is generated by springs which arise in upper Cretaceous sandstones and siltstones at the base of the Pink Cliffs (Figs. 9 and 10). He reported spring sources

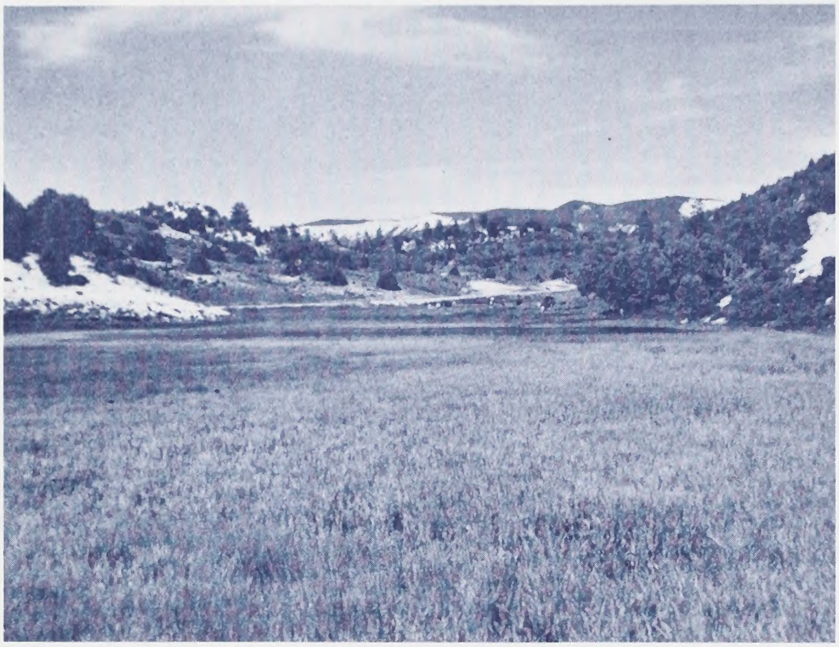


Figure 9. Headwaters of stream draining Pink Cliffs, Alton Petition Area, Kane County, Utah. This designated alluvial valley floor has potentially subirrigated native grasses.

throughout the upper Cretaceous sequence; however, he noted that the most important springs arise in the uppermost portion of the sequence stratigraphically and below steeply sloping portions of the Pink Cliffs topographically.

Goode (1964, 1966) also reported that streams lose flow in the downstream direction. For example, he reported no flow below Sink Valley in Sink Valley Wash and no flow in Kanab Creek over The Falls in summer 1963, despite perennial flow in headwater tributaries. Sandberg (1978) also described the steady loss of streamflow between gaging stations on Mill and Skutumpah Creeks.

Not surprisingly, stream diversions have been located on streams whose basin topography and geology yield sufficient streamflow for irrigation. A table listing the basin lithology and area above each existing stream diversion was developed. All but two diversions above the White Cliffs were located in basins where the Tertiary Claron formation outcrops. Drainage areas above diversions vary in size depending on how close the diversion is to a spring source. Diversions below the White Cliffs are either intermittent in use (Figs. 11 and 12) or are located below known Navajo Sandstone spring sources.

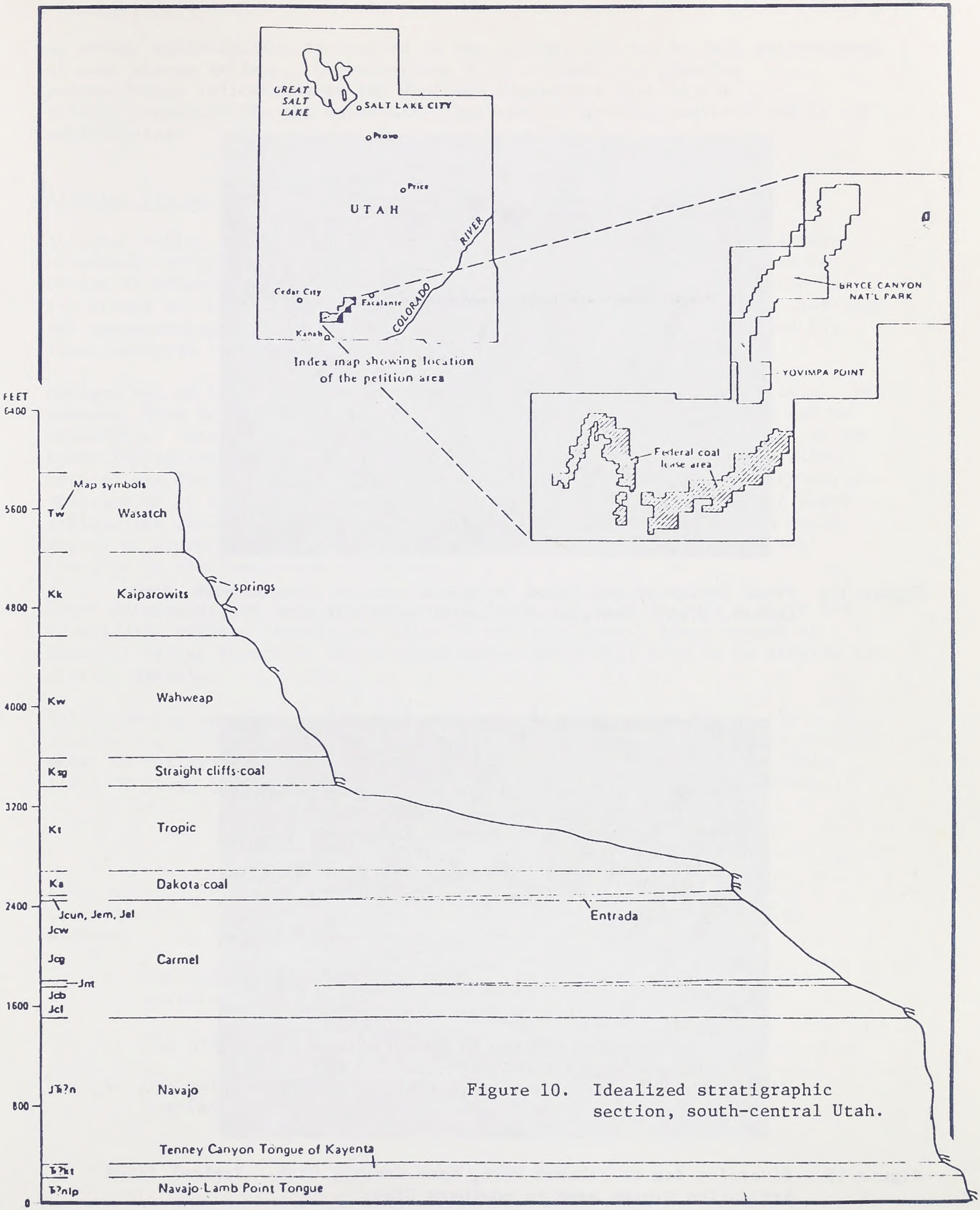


Figure 10. Idealized stratigraphic section, south-central Utah.

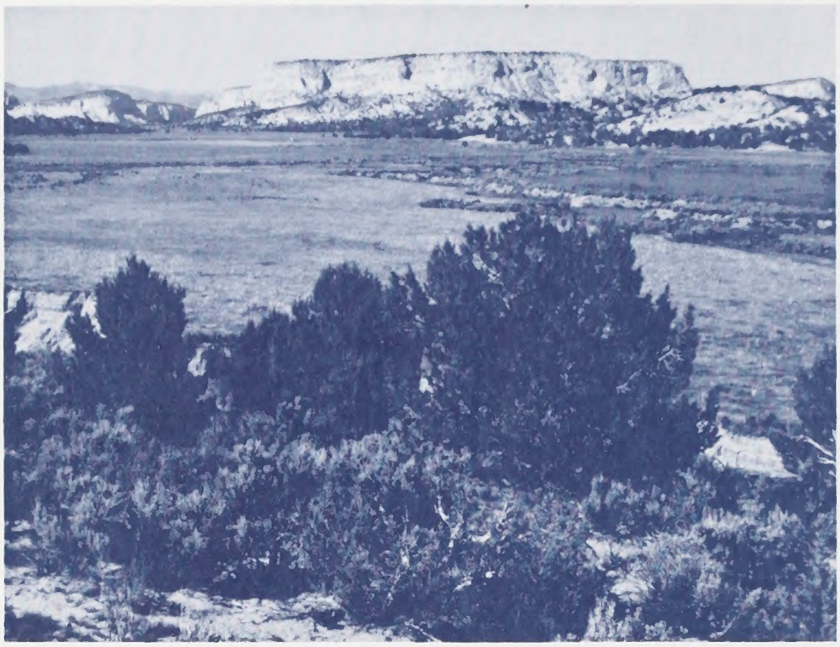


Figure 11. Flood irrigated and flood irrigable area on Johnson Wash, Kane County, Utah. Designated alluvial valley floor.

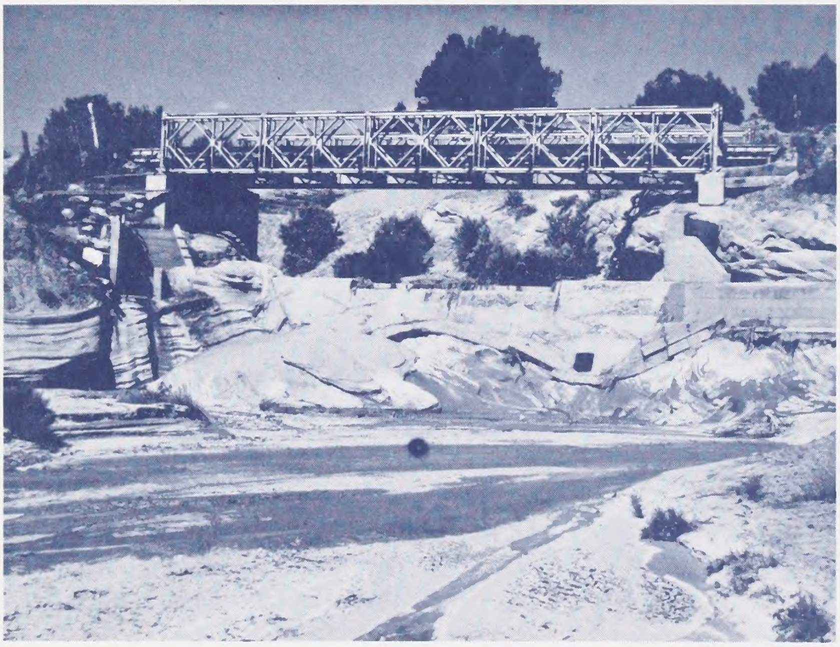


Figure 12. Diversion dam on Johnson Wash, Kane County, Utah. Typical flood irrigation system used in southern Utah.

As noted, subirrigation is limited in the region, due to the deep entrenchment of most stream valleys. Conversations with ranchers and resource professionals indicated that the dominant vegetation type of the valley--sagebrush--is not especially important to grazing patterns and is not subirrigated.

Alluvial Valley Floor Designations

Alluvial valley floors were designated in all valleys with existing stream diversion irrigation and in all valleys whose basin lithology included the Claron or Kaiparaowits formations. Thus, the basis for the designation was: (1) stream valleys with existing flood irrigation, (2) valleys whose hydrology and geomorphology are similar to those presently under irrigation, and (3) those isolated valleys considered to be subirrigated (Fig. 13).

Designation of stream reaches where there are no diversions is uncertain. For example, Sink Valley Wash below Sink Valley has ephemeral streamflow and no diversions. Kanab Creek has no diversions from Lamb diversion to that of the Kanab Irrigation Company, a distance of 24 miles. There are no diversions between the Skutumpah/Thompson diversions and the upper Johnson diversion, a distance of at least 9 miles. In preliminary determinations, each of these valleys was designated an alluvial valley floor. Formal designation would depend on hydrologic data indicating whether the valley in question was integral to the downstream diversion.

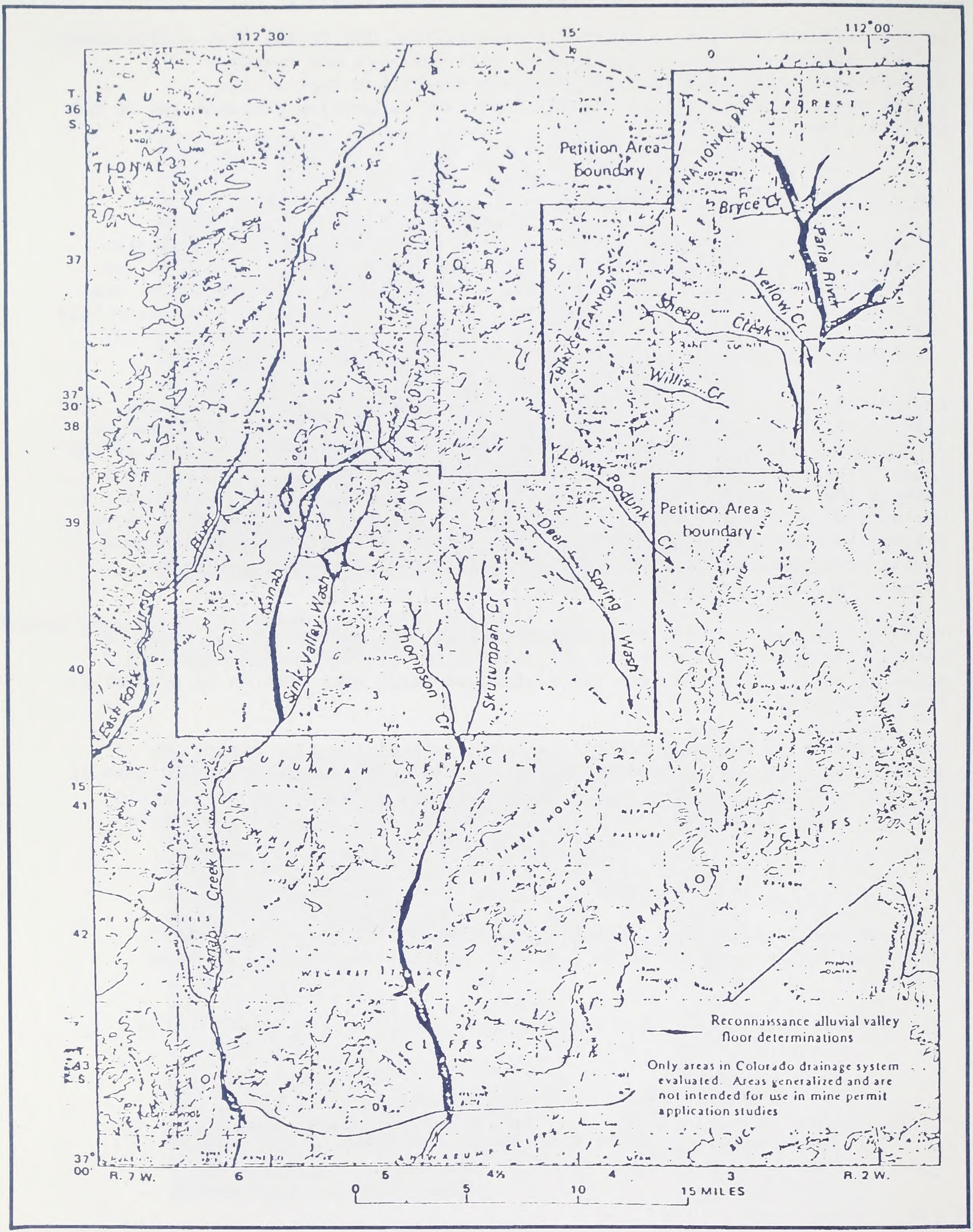
These determinations were reconnaissance level and provide only a basis for identifying valleys clearly not alluvial valley floors. Areas mapped as alluvial valley floors at the reconnaissance level will have to be studied in greater detail.

This approach to regional identification of alluvial valley floors, by delineating existing agricultural land-use patterns and assessing the role of water in valleys, follows the suggested approach of OSM guidelines. This level of study is probably most appropriate for BLM land-use evaluations.

DETAILED STUDY OF ALLUVIAL VALLEY FLOORS

If an alluvial valley floor exists in or near a proposed mine, further investigation is required to develop an understanding of the following systems:

1. The hydrology of the adjacent area which supplies water to the alluvial valley floor.
2. The hydrologic functions of the alluvial valley floor.
3. The relationship between the water availability and enhanced vegetative production on the valley floor.



Only areas in Colorado drainage system evaluated. Areas generalized and are not intended for use in mine permit application studies

Figure 13. Map of southern Utah petition area showing identified alluvial valley floors (U.S. Office of Surface Mining 1981, Fig. II B4-1).

These issues are important whether the proposed mine is adjacent to the alluvial valley floor or in the valley floor, in which case reclamation of the hydrologic systems and vegetative productivity is necessary.

In discussing the three items mentioned above, we will look at what has actually been done for a proposed mine, the CX Ranch Mine, in southeastern Montana. This case study demonstrates the investigations needed for a mine adjacent to an alluvial valley floor and also discusses the kinds of issues which need to be addressed in a permit application. Further studies are required for actual mining of an alluvial valley floor because of the need for a reclamation plan to restore the valley. These studies are described at the end of the case study.

Squirrel Creek Case Study

The lower Squirrel Creek Valley is located in southeastern Montana near the town of Decker. Two companies (Consolidation Coal Co. and Peter Kiewit Sons' Co.) planning to mine coal in and adjacent to the Valley requested that an alluvial valley floor determination and a significance determination be made by the State and Federal regulatory agencies prior to submitting mine permit applications. The Montana Department of State Lands and the Office of Surface Mining jointly established the alluvial valley floor boundaries and determined that portions which are subirrigated and/or flood-irrigated hayland would be banned from mining based on the criteria set forth in Section 510(b)(5)(A) of the Act (Montana Department of State Lands 1980). Consolidation Coal Company (1981) subsequently submitted a significantly revised permit application reflecting the ban on mining and the requirement of Section 510(b)(5)(B) to protect the hydrologic functions and productivity of the alluvial valley floor. Squirrel Creek is the only alluvial valley floor which has been declared by a regulatory authority to have areas of flood-irrigated or subirrigated agricultural activities significant to farming and therefore banned from mining.

Prior to submitting this application, Consolidation Coal Company conducted a hydrologic and vegetation investigation to assess potential impacts from mining adjacent to the alluvial deposits of the valley floor. These findings have been incorporated into the mining and reclamation plan by the company to assure preservation of the hydrologic functions and agricultural productivity of the adjacent alluvial valley floor.

Regulations prohibit disturbing the surface of agriculturally significant portions of the alluvial valley floor or impeding the normal practices of flood irrigation and agricultural production of these areas. The proposed outer limit of overburden removal at Squirrel Creek slightly encroaches on the outer limit of alluvium. Studies have shown that the intermixed alluvium and colluvium along the valley margins is fine grained and has low permeability. Locally, it is unsaturated. Accordingly, potential dewatering of the main body of Squirrel Creek alluvium must occur through fine-grained alluvium and Fort Union formation materials of low permeabilities.

The following outline addresses the hydrologic functions of the Squirrel Creek alluvial valley floor pertinent to the proposed CX Ranch Mine. The outline is broadly divided into three sections: surface water hydrology, ground-water hydrology, and agricultural productivity.

Surface Water Hydrology

Surface water hydrologic effects of the proposed CX Ranch Mine on the Squirrel Creek alluvial valley floor can be divided into potential impacts to water quantity and quality. Significant issues are listed below.

1. During mining there will be reduced ephemeral tributary runoff to the alluvial valley floor due to interruption by the active pit and associated facilities. The quantity of flows which may be so interrupted has been calculated. Consolidation Coal Company has addressed the proportional amounts of runoff lost to the alluvial valley floor and the influence this may have on agricultural productivity. Hydrologic balance analyses were also undertaken.

2. Disturbed-area runoff and active pit inflows will be directed to a series of sediment and water treatment ponds. These waters will be legally discharged to Squirrel Creek under a Montana Preliminary Draft Environmental Statement (MPDES) permit. The quantity and quality of this discharge are estimated in the permit application and the effect on Squirrel Creek is judged to be minimal.

3. Present plans for the proposed CX Ranch Mine indicate that all runoff for Dry Creek (a major tributary) will be diverted beneath spoil stockpiles. However, it is possible that, due to the nature and design of the diversion, extreme runoff events may cause some temporary impounding of Dry Creek runoff behind the stockpile. The amount and duration of this temporary impoundment is still under review and engineering design consideration. However, the Consolidation Coal Company will assess the potential impacts to Squirrel Creek Water quality by such possible temporary impoundment.

4. Although Squirrel Creek is tributary to the Tongue River and some associated facilities of the proposed CX Ranch Mine will be located near the Tongue River, the sediment control system for these facilities and other mitigating measures will not affect the Tongue River valley floor and associated agricultural fields.

Ground-water Hydrology

An evaluation of Consolidation Coal Company's preliminary mine plan suggests that potential impacts to the ground-water regime of the adjacent alluvial valley floor can be broadly grouped into four categories: (1) potential dewatering of Squirrel Creek alluvium through the face of mine cuts; (2) potential interaction of alluvial ground water with postmining spoil ground water; (3) reestablishment of alluvial and coal aquifer and spoil recharge functions; (4) potential alteration of alluvial water quality caused by settling pond infiltration.

Using various ground-water flow equations, Consolidation Coal Company has estimated the quantity of ground water that the pit excavations will intercept from the coal and alluvial aquifers. The equation variables of aquifer hydraulics and flow were determined during field investigations conducted for the normal hydrologic baseline investigation. Using the calculated aquifer leakage rates, aquifer drawdowns have been estimated in areas about the pit excavations for various periods of the mine life. Estimates of alluvial leakage and drawdown are compared with the potential recharge of the system by Squirrel Creek.

Consolidation Coal Company has used a predictive model of postmining spoil water quality based on data reported for the adjacent West Decker Mine. The company expects spoil water to have lower quality than premining water in the coal and overburden. The estimated postmining ground-water elevations indicate the premining flow pattern toward the creek will be reestablished. Predictions of the rate of spoil and alluvial ground-water interaction are based upon the calculated static elevation of ground water in spoils and the estimated permeability of the reclaimed truck/shovel spoils. A water balance analysis of the flow in the bedrock aquifers and alluvial system shows minimal hydrologic interaction of the CX Ranch Mine spoils and adjacent alluvial ground waters.

The recharge characteristics of the Squirrel Creek alluvium are identified in the CX Ranch baseline hydrologic report. Coal seams and coal overburden provide negligible recharge to valley subflows throughout the study area. Therefore, it is not expected that recharge characteristics of the alluvial valley floor will be affected by mining, because the proposed mining will not occur anywhere near the alluvium's primary recharge area.

The results of pit-ground-water inflow calculations and estimated watershed runoff have been combined and mass-weighted to predict settling pond water quality. Consolidation Coal Company's preliminary mine plans locate settling ponds on fine-grained Squirrel Creek alluvium near the valley wall. The proposed settling pond area is not an agriculturally significant area of the alluvial valley floor. Estimated infiltration rates and settling pond water quality are used to assess potential degradation of Squirrel Creek alluvial water quality.

Agricultural Productivity

Because surface mining adjacent to an alluvial valley floor has the potential to affect agricultural productivity, current productivity within the alluvial valley floor as well as expected productivity during and after mining need to be assessed. Also assessed are potential disruptions of current flood irrigation practices and ditches associated with agriculturally significant fields in lower Squirrel Creek valley and possible mitigating measures.

Agricultural productivity is determined from estimates of hay and grain production made by the rancher. Further refinements for areas with varying amounts of subirrigation and flood irrigation are made by detailed vegetative sampling.

Gaging the diversion and ditch system used for flood irrigation and examining records of water availability in previous years have been used to establish the amounts of flood irrigation water needed in the event the existing ditch system is disturbed by mining.

The effect of changes in alluvial water table levels on subirrigation is the most difficult impact to assess. Precipitation, flood irrigation, and subirrigation provide water to fields along Squirrel Creek. In dry years, subirrigation plays a more important role than in wet years; therefore, in wet years a lowered water table would have less effect on productivity than in dry years.

Data Requirements for Permits Involving Mining Alluvial Valley Floors

Where mining an alluvial valley floor is proposed, field investigations are more extensive than those outlined in the Squirrel Creek case study, because restoration of the hydrologic functions is required. Data requirements similar to those needed for the adjacent-mine situation are still applicable, but further studies must encompass all aspects of the hydrologic functions of the alluvial valley floor, especially the following:

1. Stream Geomorphology and Hydraulics--Current concepts for restoration of stream channels and flood plains involve reconstructing morphologic features present before mining that were associated with alluvial channels and not bedrock channels. Therefore, channel width and depth, sinuosity, gradient, bed and bank materials, roughness, and other factors need to be quantified prior to mining. Contributions of baseflow and runoff to total flow also need to be determined.

2. Surface Water Quality--Because reclamation of a stream channel will affect water quality of surface flows, seasonal fluctuations need to be quantified.

3. Physical and Hydraulic Characteristics of Alluvial Aquifer--Probably the most difficult challenge in the reclamation of alluvial valley floors is the restoration of an alluvial aquifer which will have flow, storage, and water quality characteristics similar to the undisturbed situation. If replacement of these characteristics is successful, the reestablished water table will be at a level sufficient to allow subirrigation. In addition, the new alluvial aquifer will have the same hydraulic buffering capability as the original system did.

   The alluvial aquifer needs to be defined in terms of thickness, lithology, permeability, storativity, waterflow, and water quality. A reclamation plan designed to reestablish an alluvial aquifer similar to one typically found under alluvial valley floors has yet to be approved by a regulatory agency or implemented at a mine.

4. Subsurface Geology--Particular attention must be paid to the hydraulic connection and permeabilities of adjacent bedrock and alluvial aquifers because all of these aquifers will be replaced with somewhat different materials. Usually the relatively porous and permeable alluvial aquifer is contained by a much less permeable bedrock aquifer. To reestablish these hydrologic conditions requires a more involved reclamation plan than that ordinarily used for small drainages.

5. Soils and Vegetation--A detailed soil survey and vegetation map are needed to design the soil salvage and replacement plan and the revegetation plan.

STATUS AND PROBLEMS OF CURRENT REGULATORY PROGRAM

The U.S. Office of Surface Mining is in the process of reviewing and rewriting its regulations regarding alluvial valley floors. It is deleting large portions of the alluvial valley regulations and will be incorporating deleted technical discussions into a handbook, expected to be published in 1982.

The new handbook will address the issues of identification, study, and reclamation of alluvial valley floors and will attempt to explain and clarify the overall alluvial valley floor regulatory program. Some of these issues are discussed below.

Problems Encountered During Implementation of Regulatory Program

As with any piece of legislation and associated regulations, problems occur in trying to use one set of rules in many different field situations. Problems have occurred both because of differences in interpretation of the regulatory language and because the authors of the Act and regulations did not anticipate the variety of hydrologic and agricultural situations which exist in the semiarid West.

One common observation among regulatory staff is that alluvial valley floor status is being afforded to many small streams viewed as having uncertain agricultural importance. Ambiguous regulatory guidelines make determinations of small streams difficult. However, further discussion indicates that insufficient attention is being paid to agricultural land use patterns in an area. As discussed in the OSM guidelines, only small streams presently utilizing surface or ground water for agricultural purposes or valleys of similar character should be designated as alluvial valley floors. If a certain type of small stream valley is not used anywhere in a region for agricultural purposes (which are dependent on the water of the valley), then these valleys should not be designated as alluvial valley floors.

A number of questions have arisen regarding the level of agricultural activity which makes a valley an alluvial valley floor. The regulations indicate that stock watering qualifies a valley for alluvial valley floor status. However, regulatory agencies feel this to be too broad an interpretation. Some States have designated subirrigated areas as alluvial valley floors on the basis of shelter provided by lush vegetation for calving. Other States disagree with this stance. In Wyoming, creation of artificially subirrigated areas by building impoundments is a common agricultural practice which enhances hay production; this use does not qualify an area for alluvial valley floor status under a strict interpretation of the regulations. Other questions also exist.

Regulations do not specifically address whether areas can be designated as alluvial valley floors on the basis of potential to subirrigate. In Montana, if a subirrigated alfalfa hayfield is separated by a barbed wire fence from a native pasture with no subirrigated species useful to agriculture, two different interpretations can be made. In the first instance, the alfalfa field is an alluvial valley floor very likely significant to farming, which would be banned from mining, while on the other side of the fence there is no alluvial valley floor (assuming no flood irrigation). Assuming both fields are on the same terrace and have similar physical and hydrologic characteristics, the only reason one field is protected is due to the whim of the rancher. It is not clear whether similar subirrigation capability not currently being utilized qualifies an area as an alluvial valley floor.

Designating areas having the potential to be flood irrigated has also posed problems. To date, expansive areas have been considered irrigable even though it is known that insufficient water exists to irrigate the whole parcel. The difficulty arises in picking a basis for determining which part of the parcel will be allocated water. Regulatory agencies have been unwilling to set up criteria for assigning the water, both because of uncertainty of future patterns of land and water rights ownership and because it is unclear whether the intent of the Act is to designate the entire parcel as an alluvial valley floor or only portions.

A crucial determination which must be made for lands currently being farmed and irrigated is whether the removal of the production from these areas would have more than a negligible impact on the farming operation. Determining what constitutes negligible impact or significance is not easy because of the diversity of farm and ranch operations. One rancher may work from dawn to dusk to pay for college educations for his children. His neighbor may be a wealthy banker who views the ranch as a retreat, and a loss of some production may not be significant.

Wyoming put together a consensus view of what significance is after interviewing farmers and ranchers, government and research personnel, and other interested people. A 3 to 10% loss of total production of the operation is considered to be significant depending on the size of the operation. Similar levels of impact will probably be adopted by other regulatory agencies as they consider each situation on a case-by-case basis.

New issues which have developed and have yet to be resolved include: (1) whether an offsite alluvial valley floor can be developed for irrigation and thus substituted for a developed valley proposed for mining, (2) whether the water rights issues of a State ought to be considered in the alluvial valley floor issue, and (3) how alluvial valley floors should be protected when only their surface is proposed for disturbance. These issues are all being evaluated by the Office of Surface Mining as part of the handbook development process.

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SOCIOECONOMIC

CONSIDERATIONS

SOCIOECONOMIC IMPACTS
OF WESTERN COAL DEVELOPMENT

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INTRODUCTION

Over the last decade, accelerated coal development in the Western United States has generated increases in employment, income, population, and community development in predominantly rural areas. These increases, in turn, have resulted in some changes in lifestyles and social structures and have sometimes caused problems in meeting growth-related needs. Coal development in the West has thus been a mixed blessing, with both positive and adverse effects on the region's human environment. These effects are commonly termed "socioeconomic impacts."

Since the scale of Western coal development is expected to grow in the decades to come, the nature and consequences of socioeconomic impacts are worthy topics of discussion. Our knowledge of how to identify, evaluate, predict, and mitigate impacts of resource developoment on the human environment has evolved rapidly since 1970. The principal processes that produce economic and population changes due to major resource development activities are now generally understood. The relationship between population growth and consequent requirements for public facilities and services can be specified within reasonable limits. Further, the implications of these requirements for county and community capital and operating budgets can also be better estimated. Finally, our ability to understand and predict the impacts of resource development actions on social structure, quality of life, and individual well-being has been significantly advanced through research efforts such as the Bureau of Land Management's 2-year project entitled "Social Effects of the Federal Coal Management Program in the West." Nevertheless, many uncertainties remain; the future is difficult to predict and socioeconomic impact assessment continues to be a rather approximate discipline.

In the sections that follow, the nature of coal development impacts on the human environment will be outlined, together with a brief description of impact assessment techniques and an evaluation of their reliability. The concluding pages examine the growing integration of socioeconomic assessment and implementation planning in both the public and private sectors.

The Western coal-producing States (Fig. 1) cover a vast area characterized by a semiarid to arid climate, low population density, and a rural, agricultural lifestyle. The region consists of Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming. Federal landholdings in these States are large, and their management affects the lives of a majority of the region's population.

Between 1970 and 1980, the total population of the six coal States grew from 5,930,541 to 7,560,040. This was a 27 percent increase, compared with an average national growth of 11 percent over the same period. Table 1 summarizes the population growth in the six States between 1970 and 1980 and demonstrates the leading role that coal energy counties have played in that growth.

FIGURE 1.
WESTERN COAL RESERVES.

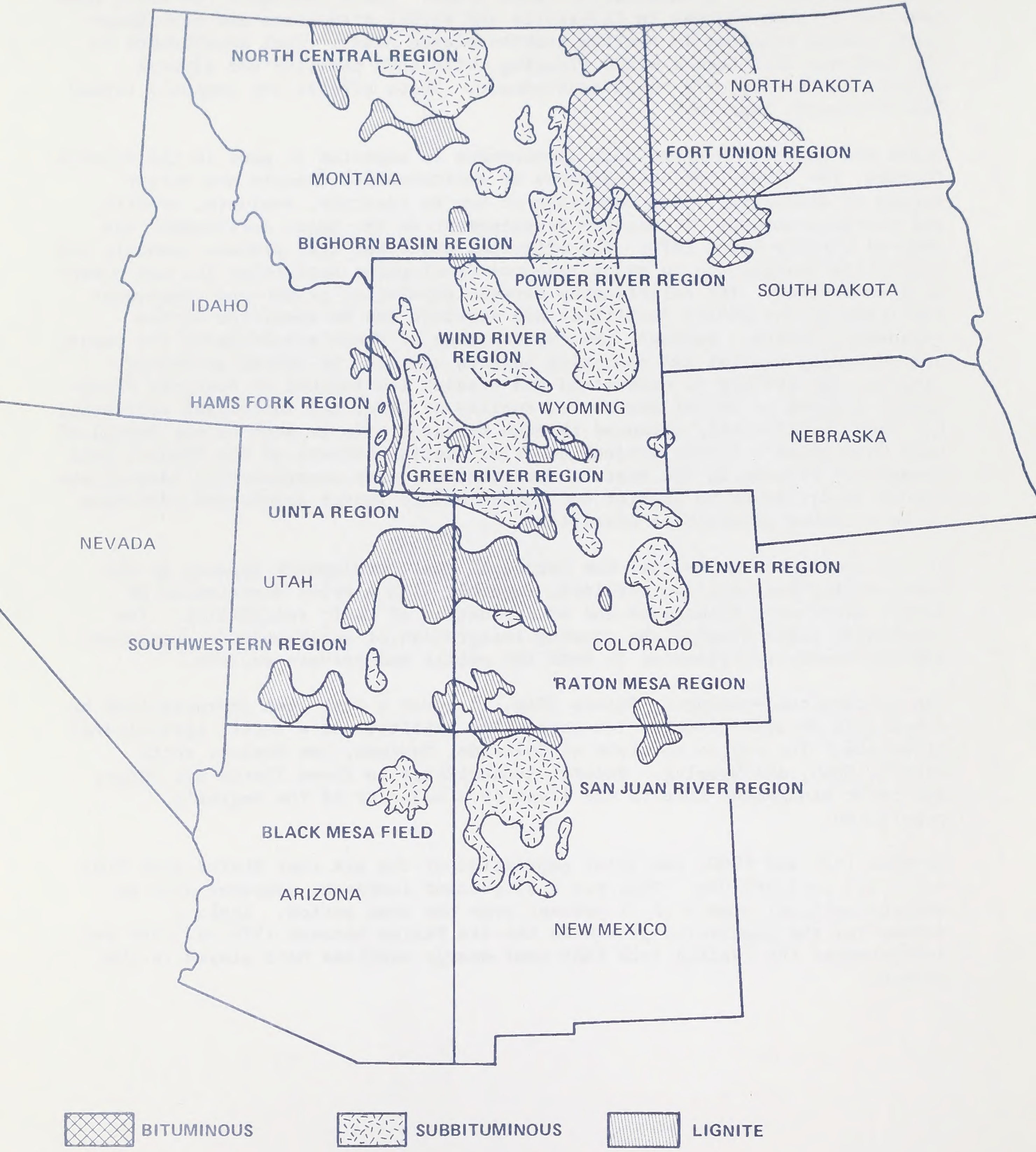


TABLE 1. POPULATION AND COAL PRODUCTION FOR SELECTED COUNTIES, 1970, 1980.

State/County	Population 1970	Population 1980	Population Percent Change 1970-1980	Coal Production (millions of tons) 1970	Coal Production (millions of tons) 1980
North Dakota	617,792	652,695	5.6	5.0	16.1
Mercer	6,175	9,378	51.9	3.6	4.5
McLean	11,251	12,288	9.2	0.0	2.1
Oliver	2,322	2,495	7.5	0.0	5.4
Montana	694,409	786,690	13.3	3.5	29.8
Rosebud	6,032	9,899	64.1	3.1	13.3
Big Horn	10,057	11,096	10.3	0.1	16.0
Wyoming	332,416	470,816	41.6	7.2	92.0
Campbell	12,957	24,367	88.1	0.6	58.2
Carbon	13,354	21,896	64.0	1.6	9.7
Converse	5,938	14,069	136.9	1.5	3.2
Lincoln	8,640	12,177	40.9	1.1	4.9
Sheridan	17,852	25,048	40.3	1.4	4.3
Sweetwater	18,391	41,723	126.9	0.2	10.1
Colorado	2,209,596	2,888,834	30.7	6.0	18.7
Routt	6,592	13,404	103.3	1.9	7.2
Gunnison	7,578	10,689	41.1	1.0	1.2
Moffat	6,525	13,133	101.3	0.4	5.3
Utah	1,059,273	1,461,037	37.9	4.6	16.6
Carbon	15,647	22,179	41.7	3.3	5.4
Emery	5,137	11,451	122.9	1.1	6.3
Sevier	10,103	14,727	45.8	0.2	1.8
New Mexico	1,017,055	1,299,968	27.8	7.3	18.7
San Juan	52,517	80,833	53.9	NA	11.8
Colfax	12,170	13,706	12.6	NA	1.5
McKinley	43,208	54,950	27.2	NA	5.4

Western coal states population increased by 1,629,499 or 27 percent from 1970 to 1980, compared with a total U.S. increase of 11 percent. While coal was not the only stimulus to growth over the decade, coal energy counties generally led State averages in terms of population increase. Coal production itself increased from 33.6 million tons per year (mmtpy) in 1970 to 191.9 mmtpy by 1980, with Wyoming the leading producer. Source: Mountain West Research, Inc., 1981.

Besides their coal energy resources, the six Western coal States are endowed with important mineral fuels and other natural resources. During the past decade, oil, natural gas, and uranium have played an important role in the region's economic and demographic development.

The expansion of energy development in the West has generated rapid employment and income growth, although it has not yet generated rapid industrialization. From a socioeconomic standpoint these trends are significant, for they indicate rapid economic change in a region that, compared with the United States average, still exhibits (1) much lower population density, (2) lower average income levels, (3) higher employment rates, (4) lower labor force participation rates, and (5) out-migration from rural agricultural areas. Such characteristics are indicative of a region where agriculture still plays a key role in economic, social and political life. Since energy development frequently competes with agriculture for land and water resources, conflicts between interests representing the two have figured importantly in some aspects of socioeconomic impact. Table 2 compares the 1970 and 1980 levels of mining and agricultural employment in the six Western coal States. While the region's agricultural employment declined by 6 percent over the decade, mining employment increased by 114 percent. Total employment in the region increased by 46 percent.

The outlook for energy resource development over the next 20 years is for continued growth in the Western coal States. While coal mining activity is expected to lag through the mid-1980's due to weak market demand and excess capacity, oil and gas exploration and production activity are expected to remain strong. Uranium extraction is likely to continue to be depressed for the next decade due to overcapacity, large stockpiles, and annual market volumes far below expectations. Meanwhile, synthetic fuels are beginning to play a role in the region, with the construction of the Great Plains coal gasification plant in North Dakota and the emergence of several oil shale projects in western Colorado. However, the development of synthetic fuels in the early 1980's has been significantly slowed by the high cost of capital, stable oil prices, and temporary surpluses, as well as by sharp cuts in Federal support for production-scale synfuels plants. The postponement of many coal-based synthetic fuels plants within the last year has had its own dampening effect on coal development.

The specific implications of coal development for the human environment are a function of the interrelationship between the characteristics of the proposed development activity (the change agent) and the key socioeconomic characteristics of the area in which the activity will occur. Coal development can be grouped into its constituent technologies: extraction, conversion, and transmission/transportation. Within these categories are (1) surface and underground mining; (2) electric power generation, coal gasification, and coal liquefaction; and (3) coal haul railroads, coal slurry pipelines, and high voltage transmission lines.

The project characteristics that result in socioeconomic impacts are summarized for each type of technology in Table 3. As shown, surface coal mines typically employ 100 to 300 workers during a 2- to 4-year construction

TABLE 2. AGRICULTURAL, MINING, AND TOTAL EMPLOYMENT (1970, 1980).

State	Agricultural Employment			Mining Employment			Total Employment		
	1970	1980	Percent change (1970-1980)	1970	1980	Percent change 1970-1980	1970	1980	Percent change (1970-1980)
North Dakota	59,316	53,461	-10	1,633	7,702	472	268,472	336,482	25
Montana	38,652	34,577	-11	6,547	8,774	34	284,991	369,799	30
Wyoming	15,039	15,557	3	11,579	35,878	210	152,646	258,965	70
Colorado	52,415	48,411	-8	14,186	35,923	153	966,886	1,485,651	54
Utah	21,416	20,138	-6	12,732	18,418	45	424,391	622,308	47
New Mexico	21,414	22,709	6	16,923	29,270	73	380,256	553,914	46
Total for region	208,252	194,853	-6	63,600	135,965	114	2,477,642	3,627,119	46

Changing employment relationships are seen between agriculture, mining and total employment on the State and regional levels. While regional agricultural employment declined by 6 percent over the decade, mining employment increased by 114 percent. Wyoming and Colorado led all States in the region with mining employment increases of more than 20,000 workers each. Source: Mountain West Research, Inc., 1981.

TABLE 3. IMPACT-CAUSING FEATURES OF TYPICAL COAL DEVELOPMENT PROJECTS.

Process/ Technology	Construction Period Duration (years)	Construction Period Labor Requirements Peak (employees)	Operations Period Labor Requirements (employees)	Local Expenditures (millions of 1980 dollars) Construction Period	Local Expenditures (millions of 1980 dollars) Operations Period (annually)
Extraction					
Surface Mine					
5 mmt/yr	2-4	100-300	250	15	6
10 mmt/yr	2-4	100-300	400	23	9
15 mmt/yr	2-4	100-300	500	27	14
Conversion					
Electric Power Generation					
400 mW	6	800	100	9	1
1,000 mW	6-8	1,800	200	16	2
Coal Gasification 250 mmcf/day	6	2,700	900	60	4
Coal Liquefaction 200,000 barrels/day	6	3,000	700	54	8
Transmission/Transportation					
Coal Haul Railroads 250-mi railroad, 40 mmt/yr	3	900	60	24	0
Coal Slurry Pipelines 250-mi section, 25 mmt/yr	8	800	250	3	3
High Voltage Transmission Lines 250-mi, 500-kV line	2-3	270	10	7	0

Construction and operations period employment and local expenditures are major characteristics that influence socioeconomic impacts of coal development projects. Mining and conversion facilities generally have larger and more geographically concentrated impacts. Impacts of linear transmission and transportation projects tend to be of shorter duration and are usually distributed along project route. Source: Mountain West Research, Inc., 1981.

period and from 250 to 500 workers during their operations period. Local expenditures for goods and services used in the construction period depend on the size of the mine and the local economy but typically range from $15 million to $27 million annually. Similarly, operating expenditures vary from $6 million to 14 million annually.

For conversion facilities, construction periods typically last 6 to 8 years, and construction employment levels of as many as 3,000 workers are well above the operating levels for each type of conversion technology. Local expenditures may rise as high as $60 million during the construction period but not above $4 million during the operations phase.

The duration and labor requirements of the construction period for each 250-mile segment of transmission/transportation projects depend on the ruggedness of the terrain, but they usually vary from 2 to 8 years and 270 to 900 workers. Operations-period employment varies from 10 workers for a transmission line to 250 workers for a coal slurry pipeline. Local expenditures vary from $3 million to $24 million during the construction period but are negligible during the operations period.

An important feature of the construction and operations period work forces is the degree to which they are composed of "nonlocal" workers, or people who move from other areas for employment on the project. These workers are different from "local" workers or nonmovers because they place additional demand on housing, public facilities and services, and commercial establishments. Another important project characteristic is the "fixed" or linear nature of the project. On fixed-site projects such as mines and conversion facilities, socioeconomic impacts typically last for several years and are concentrated in communities near the project site. On linear facilities such as railroads, slurry pipelines, and transmission lines, socioeconomic impacts usually last for much shorter periods and are distributed among the communities along the project route.

THE NATURE OF SOCIOECONOMIC IMPACT

The socioeconomic impacts of coal development projects result primarily from changes generated in employment, income, and population. These changes have repercussions on project area demand for public facilities and services (water and sewer, health care, education, social services, recreation, public safety, transportation, and public administration) and housing. In combination, these demands determine the impacts on land use and public revenues/expenditures. Finally, all of the above effects have potential to cause social impacts among members of the local population.

The socioeconomic consequences of coal development projects are best explained in terms of an impact cycle that includes construction, operations, and abandonment phases. The construction phase of a typical coal development project usually causes local employment and population to increase rapidly to peak levels and then to decrease just as rapidly to their original levels (see Fig. 2). Operations-phase employment increases are frequently well below those of the construction phase and may not even be noticeable for some linear facilities such as coal haul railroads and transmission lines, which typically employ very few operations workers. Although not shown in the figure, the abandonment phase is reached when the project has completed its useful life. Abandonment-phase employment depends on the type of project and whether it is to be left in place, moved, or replaced with another project.

As shown in Figure 2, each phase of the impact cycle can have several types of impacts. Direct impacts consist of employment generated at the project site, the influx of nonlocal workers into the project area, and all wages paid to the project workers. Indirect impacts consist of employment and income generated when the project makes local expenditures for goods and services during the construction and operations phases. Induced impacts consist of the employment, income, and accompanying population growth that are generated when direct and indirect workers and their families make local expenditures.

Other energy projects in a region or another specific type of development made possible by a coal development project can result in cumulative impacts. For instance, in Mercer County, North Dakota, several coal mines, coal-fired power plants, and more recent oil and gas activity have had a cumulative impact on several local communities. An excellent example of one energy project stimulating cumulative energy development will occur in the Powder River Basin of Wyoming when the new Burlington Northern rail line opens the area to even more coal mining activity.

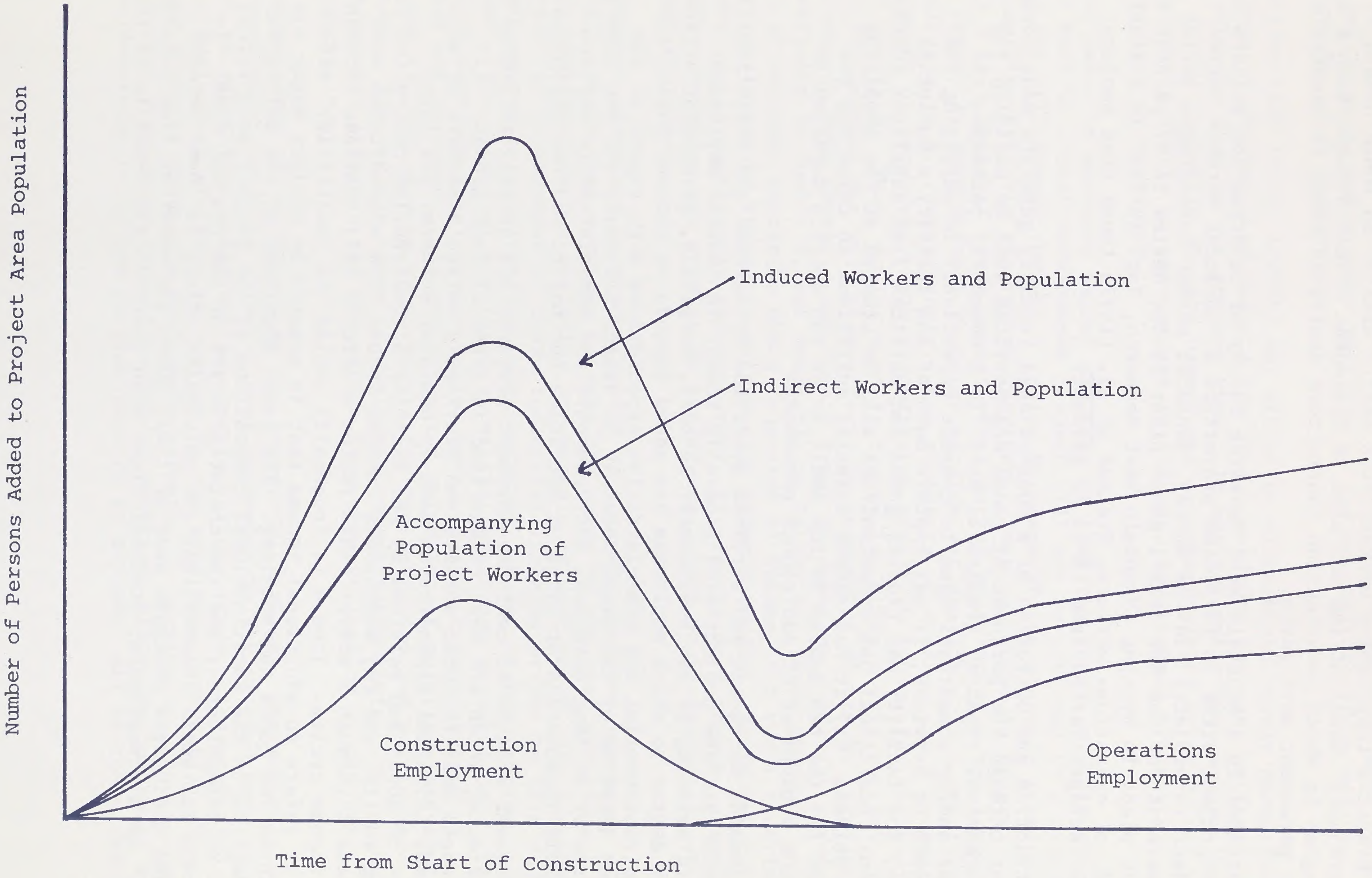
The magnitude and significance of socioeconomic impacts are determined first by the interaction of project characteristics with those of local communities. As noted earlier, the key project characterists include duration of the construction and operations periods, labor requirements, and local expenditures. The key community characteristics include labor supply, the capacity and quality of housing and commercial and public facilities and services, institutional capacity, and social structure. When combined, these key characteristics determine the number of workers who migrate to the area and the magnitude and geographic distribution of impacts on local communities. The impacts on a particular community then depend on its existing socioeconomic conditions and infrastructure and on the level of preparation made prior to the start-up of the coal development project.

Economic Impact

As the construction and operations phases of coal development projects commence, workers are hired from the local area, from other areas within the region, and from outside the region. The number of workers hired from the local area and from other areas within the region depends on the availability of local labor and whether local laborers possess the skills required for the construction or operation of the facility. As a consequence, the proportion of local workers is heavily influenced by the project's proximity to

FIGURE 2.

COAL DEVELOPMENT PROJECTS: TYPICAL EMPLOYMENT AND POPULATION IMPACTS.



COAL DEVELOPMENT PROJECTS CAUSE DIRECT IMPACTS, which consist of employment generated at the project site and the population that accompanies nonlocal project workers. Indirect impacts consist of employment and population growth stimulated by the project's local expenditures. Induced impacts consist of employment and population growth that is generated when direct and indirect workers and their families make local expenditures.

Source: Mountain West Research, Inc. 1981.

communities where large supplies of labor are available and by its proximity to other projects that employ workers with skills similar to those needed on the new project. Local hiring may also be dependent on union requirements and on the degree to which construction contractors desire to bring in members of their own permanent work force.

As demonstrated in a Mountain West Research survey of construction workers at 14 energy project sites in 1975, the proportion of nonlocal workers varies from project to project. In the survey, nonlocal worker percentages varied from 21 percent for the San Juan 1 power plant in New Mexico to 97 percent for the Wyodak plant in Wyoming (Mountain West Research, Inc. 1975). In a similar 1977 study of operations workers, Wieland et al. (1977) found that nonlocal worker percentages varied from 18 to 53 percent.

The construction and operation of a coal-related facility generate additional employment through the purchase of goods and services such as building supplies, mechanical repairs, transport, etc. If a community possesses the industrial and/or commercial base to compete effectively in supplying the needed goods or services, it may capture much of the facility's business. Otherwise, the facility may procure goods and services from suppliers outside the region. Additional job opportunities will be created at the supplying business unless: (1) it has excess capacity sufficient to cover the new demand, or (2) the new demand is too small or of too short a duration to warrant the employment of additional personnel.

The new demands for goods and services generated by workers and their families who migrate into the project area generally result in induced employment effects in existing or new businesses, schools, hospitals, government offices, etc. The degree to which employees are added depends on current capacities and on entrepreneurial and administrative expectations with regard to the volume and duration of increased demand. If demand increases are not expected to be large or of long duration, entrepreneurs and administrators may elect to expand their inventories or hours of operation but not to add new employees.

The employment effects of coal developoment projects are quickly reflected in income effects, which are best categorized in terms of four groups: (1) project wages paid to local workers who previsouly worked elsewhere or were unemployed, (2) local expenditures made by nonlocal workers, (3) local purchases of goods and services by the facility's construction contractor or operating entity, and (4) additional induced income from expenditures made under items 1 through 3 above. This factor's effects will continue through several income cycles. Item 4 is frequently called the "multiplier" effect because it refers to additional income that is created by project wages and expenditures for goods and services. The local magnitude of the multiplier effect depends on the local/nonlocal composition of the project work force, the type of expenditures, and the characteristics of the project area. In rural areas and small communities, the multiplier effect is lower because people and businesses purchase many of their goods and services from outside sources. As a consequence, nonlocal areas also share in the benefits of the multiplier effect. However, as the community and local area grow larger (in part, because of the project), it will be possible to purchase more goods and services locally, and greater portions of the multiplier effect will be captured by local communities.

Project-related income effects may either be distributed evenly among local residents or concentrated among a few local residents and many nonlocal residents who move to the project area. It has generally been argued that those in the community who are unemployed or underemployed often do not have the necessary skills to participate in the coal development project's construction or operation.

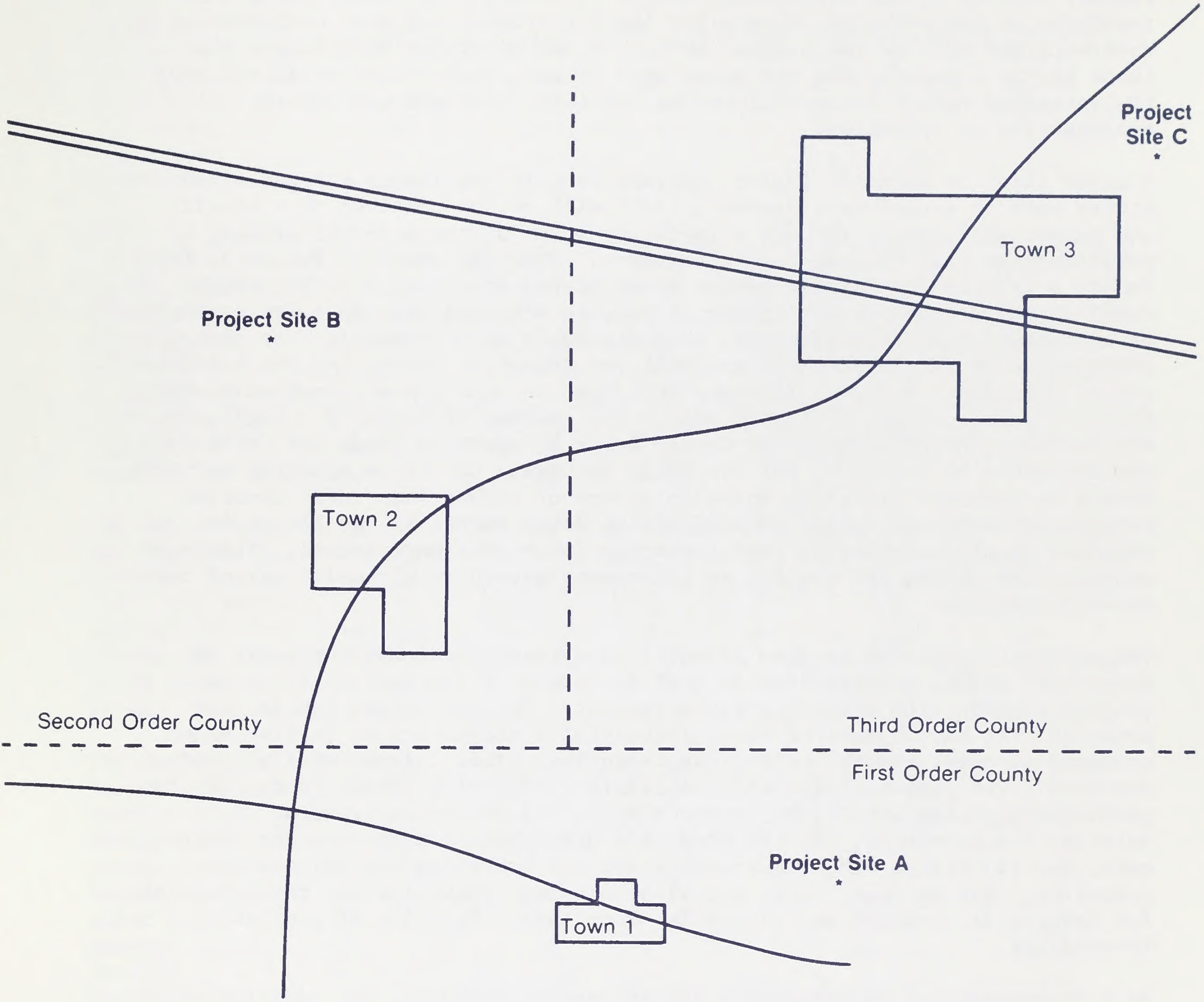
A major issue in economic impact analysis is that the income effects of an action such as a coal-development project will not be confined to a single county but will spread through a region by means of the economic trading relationships that tie the region together. Thus, as shown in Figure 3, if County B is a regional trade center whose market area includes the largely rural County A, then several goods or service not available in A are likely to be available in B. Consequently, when residents of A travel to B to obtain these goods or services, their expenditures result in income for the businesses of County B. Thus, an increase in income in County A will not only affect County A's economy but will also affect the economy of County B. Similarly, the income in both County A and County B may be spent on goods and services not available in County B, but available in County C. These spending patterns create an economic hierarchy where injection of income into rural counties results in increased income in neighboring urban counties. As income is expanded in all counties in the hierarchy, it creates more income, stimulates economic expansion, and results in employment growth in virtually all of the economic sectors.

The economic hierarchy is also affected as a result of local purchases of materials, goods, and services to meet the needs of the coal development project construction and operation processes. In most cases, the largest potential for development of these industrial linkages arises in five major economic sectors: construction, manufacturing, trade, transportation, and services. The potential for these satellite industries arises from: (1) the project's need for local subcontractor work, (2) the transportation of material and personnel, (3) the project's purchases of materials and equipment, and (4) the service requirements for the operation and maintenance processes. For certain types of coal-development technologies, the potential for industrial linkages may also arise from the utilization of project by-products.

As a consequence of opportunities for industrial linkages, the addition of coal development projects affects local economies by making them more self-reliant as additional construction, manufacturing, trade, transportation, and service businesses are able to operate in the area more profitably. When combined with the project's employment effects, in particular, the increased local income from these expansions and/or additions allow the business- and household-serving trade and service sectors to expand. All of these changes

FIGURE 3.

INJECTION OF INCOME INTO ECONOMIC HIERARCHY.



THE INJECTION OF INCOME TO PROJECT WORKERS in County A results in income effects for nonproject workers in counties A,B,C. Research done in 1977 by Chalmers, et al., indicated that in the northern Great Plains states, $1.00 of income paid to a worker at the project site in rural County A would eventually cuase personal income to increase by $1.23 in County A, $.43 in County B, and $.38 in County C, where more goods and services are available.

Source: Mountain West Research, Inc., 1981.

provide the local economies with the needed population and income bases to supply many of the goods and services that were previously supplied by more distant market centers.

The growing demand for labor from the project and its indirect employment effects, together with rising wage and salary levels, can lead to increased labor force participation rates among local residents. The increase is often most noticeable among women, whose rate of labor force participation in Western coal states has traditionally been lower than the national average.

The creation of high-paying, coal-related jobs in rural areas that have experienced population out-migration due to a lack of job opportunities often causes people to move out of lower paying jobs in other sectors. If these vacant jobs are not filled by new labor force members or by in-migrating, nonlocal workers, local wage rates and interindustry competition for labor are likely to increase. However, it is important to note that in all of these cases, an individual's choice to out-migrate, to join the labor force, or to change jobs may be dependent on how long the new project-related employment opportunities are expected to last.

Higher local incomes and population growth appear to have the potential to cause local price increases. Generally, price increases seem to be due to an excess of demand for goods over supply and the opportunity that excess creates for businesses, landowners, and others to charge "what the market will bear." Cases of outsiders being charged higher prices for goods than locals are not rare. A planner in Mercer County, North Dakota, simply attributed the price effect to greed. On the other hand, Thompson's (1979) longitudinal study for the Old West Regional Commission found inconclusive price effects in two impact cases (Wyoming and North Dakota) compared with similar nonimpact cases (in Montana and Nebraska).

In coal development areas, the rapid growth of employment opportunities and consequent population in-migration result in significant new demand for housing, public facilities and services, and private retail and service establishments. For local governments, these problems can be especially severe during project construction phases, when public revenues lag behind public costs. Government administrators are faced with the problems of allocating scarce capital resources to increase public service levels and of arranging debt financing for capital facilities that could leave the communities with carrying costs long after construction workers and their families have left. Government administrators may also be forced to recruit additional staff when local labor is in short supply and to plan for and process development requests that cannot always be supported by the existing physical infrastructure. In the private sector, firms and individuals who desire to build housing or expand their businesses may also be faced with local shortages of capital, manpower, and land. Their ability to attain these resources often depends on their previous experience and on the degree of certainty with which nonlocal capital and labor sources perceive local development.

Demographic Impacts

A critical piece of information for local planners and decisionmakers is the amount and timing of population increase with which their communities and counties must cope as a result of coal-related developments. In most cases, estimating population impacts is difficult and depends on a variety of important parameters.

Direct and indirect employment are the key determinants of total population change resulting from a given coal development project. In particular, employment of nonlocal workers who move to the project area provides the basis for population change. These population changes are usually temporary during the project's construction phase and permanent during the operations phase. However, as demonstrated in Mercer County, North Dakota, and Campbell County, Wyoming, a succession of coal-related projects can allow construction workers to become permanent residents of local communities.

As noted earlier, the magnitude of project-related population impacts in any given county or community depends on the project's labor requirements and the share of nonlocal employment that resides in the particular county or community. The portion of nonlocal labor that elects to reside in a particular community depends on the size of that community, its distance from the project site, the amenities it offers, the availability and cost of housing or commercial lodging, and other pertinent local considerations compared with other, competing residential locations.

The magnitude of the population impact depends on the share of in-migrating workers who are married and/or accompanied by their families to the local area. As shown in Table 4, the family accompaniment characteristics for nonlocal construction workers vary by the type of resource development. Project workers on linear facilities such as transmission lines and pipelines are less likely to be accompanied by spouses and children than are their counterparts on fixed-site energy and water projects. When these accompaniment characteristics are combined with fixed-site workers' more lengthy stays in local communities, it is not surprising that they generally place heavier burdens on local housing and public and private facilities and services.

Another important characteristic of the in-migrating population is its age/sex composition. Because in-migrating workers tend to be younger and have younger children, they and their families are more likely to place additional demands on educational and recreational facilities than on health-related facilities and services. In addition, the in-migrating populations near project sites are typically composed of disproportionately large numbers of young, single, or unaccompanied males whose effects on local eating and drinking establishments are more significant than those of a more evenly composed population. The younger in-migrant population can also have effects on social interaction and on membership and characteristics of various social groups and organizations. And finally, the distinctive age/sex composition of the in-migrating population affects the local demographic structure and, through a change in

TABLE 4. AVERAGE POPULATION INFLUX PER 100 NONLOCAL CONSTRUCTION WORKERS.

Type and number of projects	Not married	Married				Average population influx per 100 nonlocal construction workers
		Family not present	Family present			
			Worker	Spouse	Children	
Transmission lines (N=6)	28.5	41.0	30.5	30.5	37.2	167.7
Pipelines (N=4)	33.7	50.0	16.3	16.3	13.5	129.8
Energy (N=14)	24.6	26.5	48.9	48.9	78.9	227.8
Water (N=12)	26.8	25.7	47.5	47.5	66.4	213.9

Average population influx per 100 nonlocal workers is much larger for workers on fixed-site energy and water projects than it is for linear transmission line and pipeline projects. Difference is easily explained by fact that fixed-site workers reside in places for longer periods of time, where housing, schools, and other facilities for accompanying family members are more readily available. Source: Mountain West Research, Inc., 1981.

vital rates, its potential for population growth. Many rural coal development areas have recently experienced significant employment-related out-migration among their younger members. As a consequence, young people (particularly those of childbearing age) who enter the population as a result of an energy project revitalize its demographic structure by increasing birth rates and lowering death rates. When combined, these effects increase the local population's growth potential.

Coal developoment projects also affect the occupational structure of the local population. Most importantly, by providing employment for skilled workers, projects attract craftsmen to the area, where they become part of the local labor force. In addition, the coal-related facilities may also increase the skill levels of long-time local residents through on-the-job or other local training programs. In socioeconomic impact assessment, increases in skill levels are important because they increase the number of local workers who are available to work on subsequent energy projects.

Public Facilities/Services Impacts

Population increases have an obvious impact on community facilities and services. This impact is usually characterized by a temporary, intense demand period during the coal developmet project's construction phase and a longer term, less intense period during the operations phase. The magnitude of the facilities and services impacts depends on the existing capacity and the volume of new demand. Services such as education and health can be expanded relatively rapidly through schedule changes (double sessions, more outpatients, etc.) or by adding staff, although the quality of the service may suffer. On the other hand, capital facilities, such as water and sewer systems, streets, and parks usually require greater monetary investment and longer lead times for expansion. Moreover, since they tend to be constructed through debt financing, capital facilities can leave communities with carrying costs that extend beyond the lifetime of construction activities.

The rapid population and economic growth associated with large fixed-site coal development projects typically result in increased demand for water and new community consumption patterns. In Price, Utah, energy-related population increases in the early 1970's resulted in a moratorium on new hookups outside the city in 1974. Although the moratorium has since been rescinded, water hookup fees of $2,500 to $4,500 have limited residential growth in the area.

Rapid population and economic growth have had similar effects on wastewater treatment systems. If existing wastewater treatment facilities are operating close to or at capacity, they may have to be expanded or upgraded to accommodate increased demand. In addition, new consumption patterns and increased residential densities may require changes in wastewater treatment technologies or conversion from individual waste disposal units to community systems.

Impacts on solid waste facilities depend on the unused capacity of existing landfill areas and on the amount and type of waste generated by the coal development project and its related population and economic changes. In some cases, these increases in demand may be accommodated by expanding the landfill area. In other cases, particularly when residential development takes place in rural areas, formal collection systems may have to be devised to collect, transport, and dispose of solid waste that was previsouly handled by individual landowners.

In Western coal areas, coal development projects' transportation impacts are greatest on the road systems in the project area, between the project area and local communities, and in the local comunities themselves. These impacts occur because new demand is placed on existing road systems by project workers, other project-related traffic, and individuals who are part of the population increase stimulated by the project. The impact of higher traffic levels varies by location but is most often realized in the form of traffic congestion, increased accidents, noise and air pollution, higher road maintenance costs, and increased parking difficulty. In addition, some areas' transportation patterns have been adversely affected by the presence of coal unit train activity in the communities and at railroad crossings. When combined, these impacts can significantly affect the residential location decisions of in-migrating workers and restrict the accessibility of local community facilities for both new and long-term residents.

Population increases in coal area communities affect the level and quality of police, fire, ambulance, and other safety-related services. The demand on police services is reflected in a need for more officers, patrol cars, and office space, and for crime prevention programs. The demand for fire protection is reflected in a need for additional fire-fighting personnel and equipment and in additional demand on the local water supply. Ambulance services may have to be increased to serve not only the general population increase, but also the project area, where construction and operations activities pose new occupational safety concerns.

An in-migrating population's impact on schools in coal-development project areas depends on the number of new school age children and their educational needs, and on the physical plant and personnel capacity of local schools. If the impact is small enough, class sizes can be increased, double sessions can be scheduled, and new teachers can be hired. However, larger impacts must be met with added teachers, administrators, and support staff and/or physical plant expansions. Some impacted communities, such as Colstrip, Montana, have been able to meet temporary demand increases with portable classrooms and large teaching staff additions. Other communities, such as Price, Utah, have been able to provide temporary classrooms but have found it difficult to recruit and hold teachers because of local housing shortages and the highly competitive wages being offered in the local mining industry.

The impact of population growth on health care systems depends on the age/sex composition of the in-migrating population, their health care needs, and the capacity of existing health care facilities and personnel. When the current capacity is not sufficient to meet the increased demand, population growth strains existing medical resources and makes them less available to local residents. During construction periods, local health officials' ability to meet increased demand is often hampered by difficulties in financing capital facilities that may be required only temporarily and in recruiting physicians, dentists, and other skilled personnel during the turmoil associated with rapid population growth.

In rapidly developing areas, an influx of new residents who must adjust to new lifestyles and/or live without the amenities to which they are accustomed typically increases the demand for mental health services and alcohol- and drug-abuse treatment programs. Because these types of services require specially trained personnel that may not currently be available in coal development areas, local communities often have difficulty in satisfying these new demands.

The population increases associated with large coal developoment projects have significant impacts on rural and urban recreation. Although most Western coal areas appear to have ample space for rural outdoor recreation, the magnitude of population increases frequently causes the availability of recreational land to become a problem and may lead to restrictions in recreational opportunities. Some of the most common problems associated with large population influxes in rural areas are trespassing on private land, ignorance of traditional local values attached to the use of public lands, and poaching of wildlife.

In local communities, population increases result in more demand for baseball and softball fields, gymnasium space, parks, playgrounds and other types of indoor and outdoor recreation areas. Because project workers typically have different recreational needs than long-time residents, communities face demand for several new types of sports and recreational facilities. The responsibility for providing some of these facilities, such as parks, tennis courts, and baseball fields, may fall on the public sector. The provision of others, such as bowling alleys, movie theaters, and racquetball courts, typically relies on private sector development. The development of both public and private sector facilities may represent a beneficial impact of coal development if the recreational opportunities available to long-time residents of the community increase and/or diversify.

Large population increases pose complicated types of problems for community and county administrators because they create simultaneous demands on housing, land, and all of the public facilities and services described above. In Converse County, Wyoming, following rapid energy-related population growth in the 1970's, local administators were left to deal with difficult resource allocation issues that required significant increases in personnel and expertise. In the case of housing and land development, which were primarily dependent on the private sector, public administrators were faced with new types of growth issues and with the task of regulating, reviewing, permitting, and monitoring development. Furthermore, the coordination of both public and private sector development was complicated by uncertainties that surrounded the magnitude of energy-related impacts and by the desire to provide needed facilities but to avoid excessive long-term debt. The county initially resisted any organizational or administrative changes, but eventually it hired professional planners and an administrator, instituted a comprehensive land use plan, and adopted subdivision and other development regulations.

Housing Impacts

Population increases generated or induced by the construction and operation of coal development projects have important impacts on housing in local communities and rural areas. Their magnitude depends on demand increases and on the local supply and quality of existing dwellings (houses, apartments, and mobile homes), camper and recreational vehicle hookups, hotel/motel accommodations, and rooms for rent.

Local communities' abilities to meet increased demand for housing depends on their current stock and on their capacity to build new units. The ability of the current housing stock to hold new residents is a function of the number and type of units in the inventory, vacancy rates, and housing conditions, which reflect probable demolition rates. Available hotel/motel units and camper/recreational vehicle hookups are also an important component of the housing inventory and can be the most desired form of housing on linear coal development projects, where workers remain in any one community for only a short period. The capacity of local communities to supply new housing depends on a variety of factors, including government policy regarding residential development, sewer and water capacities, land availability, and developers' and builders' capabilities to build or install housing units. Local developers' and builders' capacities are in turn dependent on the availability of construction financing, labor, and building materials.

The nature of housing demand varies with the type of project. As shown in Table 5, nonlocal construction workers on linear projects such as pipelines and transmission lines usually stay in hotel/motel rooms, commercial campgrounds, trailer courts, rooming houses, or short-term lease apartments or houses. Fixed-site construction projects such as mines, power plants, and conversion facilities generate greater demand on the local housing market because they draw in greater numbers of nonlocal workers who expect to stay for a longer duration. In these cases, pressure on the transient lodging market is still high, but most of the pressure falls on single-family detached homes, apartments, and mobile homes. The demand for each type of housing depends primarily on the number of workers the project employs, but also on their income, expected length of stay, and family accompaniment patterns. As workers' income, expected length of stay, and family accompaniment rate increase, so does their demand for permanent dwelling units.

The presence of construction and operations workers, whose skills and incomes generally exceed those of local residents, can have varied effects on the housing market. In the absence of a major housing development effort before their arrival, the most noticeable effect of construction and operations

TABLE 5. COMPARISON OF HOUSING TYPES USED BY TRANSMISSION LINE, PIPELINE, ENERGY PROJECT AND WATER PROJECT CONSTRUCTION WORKERS (PERCENT).

Type of dwelling unit	Project type							
	Transmission line		Pipeline		Energy project		Water projects	
	Local (N=13)	Nonlocal (N=162)	Local (N=76)	Nonlocal (N=176)	Local (N=0)	Nonlocal (N=397)	Local (N=311)	Nonlocal (N=353)
Single family	47	6	66	6	-	19	71	30
Apartment	8	8	8	13	-	10	6	20
Mobile home	15	10	18	7	-	53	20	26
Travel Trailer, van, RV	15	46	4	24	-	-	2	17
Motel	15	28	1	42	-	-	-	-
Sleeping Room	-	-	-	1	-	-	1	6
Other	-	2	3	7	-	18	-	1
Total	100	100	100	100		100	100	100

Construction worker housing demand varies with type of project. While transmission line and pipeline workers are more likely to live in travel trailers, vans, RVs, or motel rooms, fixed-site energy and water project workers are more likely to live in single-family detached homes, apartments, and mobile homes. Source: Mountain West Research, Inc., 1981.

workers' presence is usually an increase in rental and sales prices and a decrease in the number of vacant units. When combined, these two effects can force local residents, who are less able to compete for adequate units, to occupy older and poorer quality housing or to move to other areas where housing is more affordable.

The market response to increased housing demand depends on the supply constraints outlined earlier and on the willingness of builders, developers, financial institutions, and local governments to provide additional housing units. What these suppliers actually build depends not only on demand for specific types of housing units, but also on the suppliers' perceptions of the future. If suppliers expect demand for permanent single-family and multifamily dwelling units to be of long duration, they are likely to cooperate in financing and building such units. However, if they expect demand for permanent units to be of short duration (for example, during project construction periods), they are not likely to build such units even in the presence of strong demand. Consequently, permanent dwelling units are built during construction periods only if they can be justified by expected long-term demand. Local developers may be willing to satisfy construction-period demand with mobile homes, but even this type of development may be limited by expectations that demand will not be of sufficient duration to justify investment in mobile home courts.

Land Use Impacts

The immediate need for new dwellings, expanded facilities, and other physical plants can often lead to nonoptimal use of land resources. In the rush to build, subdivisions may be placed in questionable locations, and there may be a lack of attention to the provision of green areas and other amenities important to the overall character of an area. This is a problem particularly when new residential developments are located adjacent to communities but outside of the local government's jurisdiction. The preparation of guidelines regarding subdivision development and the identification of the most suitable areas can be of some use, but quite often the most important determinant of land use impacts is the political jurisdiction and the actual legal and permit requirements governing developments.

Fiscal Impacts

Revenues from the construction and operation of a coal development project generally exceed the costs of providing facilities and services for the population increases associated with the project. However, there are frequently timing and jurisdictional problems that prevent the revenues from arriving where and when they are needed. The timing of revenue flows is often a problem for impacted areas because taxes on the projects themselves are realized during the operations phase, after communities have been faced with the front-end costs of expanding facilities and services to meet the population increases of the construction phase. Even when projects begin operating, they are usually located outside municipal boundaries, where long-term tax revenues accrue only to the county and State. Where provisions exist for sharing county and State revenues with impacted communities, revenues resulting from coal development are available to deal with growth costs. However, where such provision does not exist or is subject to delays, the revenues either do not reach the impacted communities or do not arrive there in time to finance needed developments.

A unique example of this problem involves a State jurisdictional problem between Wyoming and Montana. Although many coal miners who work at facilities in southeastern Montana live in Sheridan, Wyoming, State severance and local property taxes accrue only to State and local governments in Montana. Consequently, there is a significant imbalance between the distribution of mitigation costs, which are incurred in Wyoming, and project-derived revenues, which accrue to Montana.

The Western coal States have historically used two primary methods of taxing coal development projects. The ad valorem property tax, which is used by all of the States, is applied to the value of the coal deposit and/or to the coal mining or conversion site. Severance taxes are a more recent phenomenon in North Dakota, Montana, Wyoming, Colorado, and New Mexico, and are levied on the quantity or value of coal produced.

Western coal States also assess corporate income taxes, sales and use taxes, and individual income taxes. Because these taxes vary by State and typically compose only small percentages of total State revenues that accrue from the development, they are not detailed here.

Local school districts, counties, and cities receive revenues from coal development projects primarily in the form of property taxes and sales and use taxes. While school districts and counties tax coal developoment projects directly, the projects are usually located outside corporate city limits and therefore do not usually contribute property taxes directly to cities. However, projects usually have indirect property tax effects on cities in the form of property taxes paid by project workers and other members of the project-related population influx who reside there. Although the majority of sales and use tax receipts are often not channeled directly back into impacted communities, in several states (Wyoming and New Mexico, for example) legislative action has allocated a portion of local sales and use tax receipts to counties and municipalities where major energy projects are under way.

If significant population growth occurs in a particular community because of coal development, the level of fiscal impact depends on the existing tax base and/or the excess capacities of public facilities and services. Because most coal development occurs in sparsely populated areas, public facilities and services rarely have the excess capacity to meet all the needs of the new population. Funding for the necessary expansion is frequently a problem. The level of fiscal impact on local capital and operating budgets depends on the expansion requirements in each major facility and service category. These requirements, in turn, relfect the magnitude and characteristics of the in-migrating population and the relative size of construction period and post-construction period populations. This second factor is important because, in terms of additional capital investment, expansions must be tailored to post-construction population levels. However, the provision of temporary facilities and services during the construction period can be expensive on a per-capita basis, and operating budgets can increase dramatically.

The above problems are often complicated by other social and economic impacts of the coal development project. In the case of law enforcement and social services, costs of providing new facilities and services often rise faster than the population level because communities must formalize programs and rely less on informal social controls. In addition, the high wages offered by the coal development project often drive up local public and construction sector wages and hamper local communities' ability to retain experienced employees andfinance the construction of new community projects.

Social Impacts

The most difficult area of impact assessment concerns the social impacts of a coal development project. The difficulties arise not only from the absence of well-defined parameters by which social impact can be measured, but also from the investigators' inability to attach positive or negative values to processes of social change. Consequently, in discussing the social impacts of coal development on communities and individuals, this section will avoid any judgments regarding whether these effects are good or bad.

During the construction and operations phases of a project, nonlocal workers and their families become temporary or permanent residents of local communities. However, because they are outsiders, they often have different values than community residents and may be further differentiated by their eating, social, and living habits and by the fact that they are, on the average, better paid. Consequently, the absorption of nonlocal workers and their families into the local communities is very dependent on how their social characteristics compare with those of the community, Furthermore, the community's reception of a large nonlocal population is also dependent on whether the community is urban or rural, large or small; agricultural, industrial, service-oriented, or academic; and whether the community has had recent experience with social or economic change.

The in-migrating population can have a wide variety of social impacts on local communities. These include, but are not limited to change in:

1) The demographic composition of the community, particularly change in cultural or ethnic group composition;
2) Political institutions and the local power structure;
3) Civil and criminal code violations;
4) The quality and character of the educational system;

5) The economic profile;
6) The accessibility of public and private services to individuals;
7) The community's religious makeup;
8) The composition, membership, participation, and power in informal groups and organizations;
9) The residents' "image" of the community; and
10) Welfare and financial compensation.

Social impact on communities is difficult to evaluate. In some cases, relatively large changes have occurred due to energy development projects but were not very apparent because the community was experiencing a great deal of social change anyway. In other cases, delicate social balances in communities have been disrupted by relatively small population impacts, and the perceived social impacts were large.

In addition to their overall impact on local communities, the above changes affect individuals' satisfaction with their communities and perceptions of their quality of life. Individuals' perceptions of the total group of changes are likely to depend on their social and economic position in the community. For instance, members of the local business community are likely to perceive coal developoment as bringing about an improvement in their quality of life because of the economic opportunities it affords. However, other local residents who appreciate the community for its housing and recreational opportunities may perceive the changes differently because of adverse effects on housing prices and recreational facilities. And finally, in many Western coal areas, individuals who take pride in their communities' rural qualities may view the population increase and economic changes as an urbanizing force. As a consequence, they may feel the coal development detracts from their quality of life by decreasing their sense of security, integration, and cohesion with the local community.

Cumulative Impacts

In Western coal areas, the magnitude of energy resources and the interdependence of energy projects often lead to the simultaneous development of several projects with overlapping impact areas. Local communities and planning jurisdictions experience the effects of these multiple projects in the form of cumulative impacts.

In addition to their potential for increasing the local impact on housing or a particular facility or service, cumulative impacts increase the complexity of planning and resource allocation decisions for local planners and administrators. When these decisionmakers must respond to the impacts of several energy projects, many of which are uncertain until construction actually begins, their capacity to gather and provide adequate information on any one project is often strained. As a consequence, changes in the timing or work force schedule of one or more projects are likely to decrease decisionmakers' planning time and adversly affect the quality of their response. The overbuilding, temporary shortages, or makeshift solutions that result place additional stress on the communities and the decisionmakers and often decrease their willingness and capacity to plan for and respond to future changes.

METHODS OF SOCIOECONOMIC IMPACT ASSESSMENT

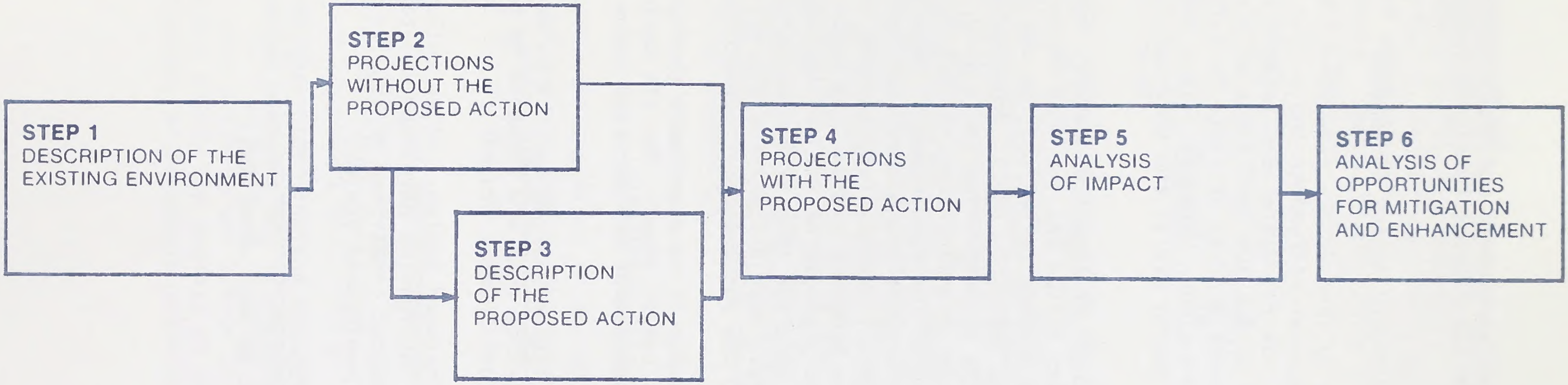
The purpose of impact assessment is to foresee the consequence of a particular proposed action in terms of defining what difference the action will make. The definition of impact, therefore, is the difference between conditions as they would exist without a proposed action and conditions as they would exist with a proposed action. The assessment process attempts to define these two sets of conditions so they can be compared. Moreover, since impact assessments are usually predictive, they embody all of the uncertainties usually associated with the future.

For coal development projects, the type of impact assessment carried out depends on the nature of the proposed action and the area in or near which it will occur. The type of assessment depends on the parties who have an interest in evaluating it, including industry, public representatives of local communities, interest groups opposing or supporting the action, and State or Federal agencies that have regulatory or administrative jurisdiction over the impacted area or the resources proposed for development. Each of these parties needs impact information to support project-related decisions concerning compliance with environmental statutes/regulations, the political desirability or acceptability of the proposed action, the scale and timing of community planning response, and the planning of project implementation. Information needs differ depending upon the type of decisions to be made and the resources available to make them. Such differences are reflected directly in the focus and level of detail of the socioeconomic impact assessment.

As was implied above, each subcomponent of an assessment (economic, demographic, housing, etc.) has several common steps. The six basic steps that typically compose a socioeconomic assessment are outlined below and are presented visually in Figure 4:

> Step 1: Description of the Existing Environment. This step focuses on those socioeconomic characteristics that are expected to be seriously affected by the proposed coal development project.
>
> Step 2: Projections without Proposed Action. Often called the "baseline forecast," this step uses the information developed in Step 1 to make projections of future environmental conditions as they would exist in the absence of the proposed coal development project.
>
> Step 3: Description of the Proposed Action. This step develops information on those characteristics of the proposed project to which the socioeconomic environment will be most sensitive.

FIGURE 4.
STEPS IN THE IMPACT ASSESSMENT PROCESS


STEP 1
DESCRIPTION OF THE EXISTING ENVIRONMENT
STEP 2
PROJECTIONS WITHOUT THE PROPOSED ACTION
STEP 3
DESCRIPTION OF THE PROPOSED ACTION
STEP 4
PROJECTIONS WITH THE PROPOSED ACTION
STEP 5
ANALYSIS OF IMPACT
STEP 6
ANALYSIS OF OPPORTUNITIES FOR MITIGATION AND ENHANCEMENT

THE SIX BASIC STEPS IN THE IMPACT ASSESSMENT PROCESS are applied to each environmental subcomponent (economic, demographic, housing, etc.) of the socioeconomic assessment.

Source: Mountain West Research, Inc., 1981.

Step 4: Projections with the Proposed Action. Often called "with-project forecast," this step uses the information developed insteps 1, 2, and 3 to project environmental conditions as they would exist with the proposed coal development project.

Step 5: Analysis of Impact. This step compares the with- and without-project projections developed in steps 2 and 4 in order to define the impact of the proposed coal development project. Once the impacts have been determined, their significance can be evaluated from the perspectives of various interested parties.

Step 6: Analysis of Opportunities for Mitigation and Enhancement. This final step examines the impacts identified in Step 5 and proposes ways of lessening the adverse effects (mitigation) and increasing the beneficial effects (enhancement) of the proposed coal development action. This step also considers the benefits of proposed mitigation and enhancement measures in light of their costs.

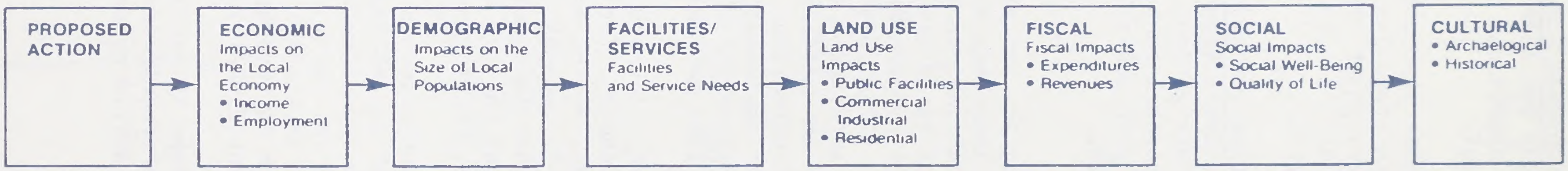
The National Environmental Protection Act and similar State legislation have resulted in impact assessments that sometimes do not generate information relevant to the planning process. In fact, socioeconomic impact assessment can be a very useful planning tool if it is allowed to affect the characteristics of a proposed coal development project through an interactive planning process. This process begins with a relatively broad range of project alternatives, which are narrowed down in an attempt to minimize impacts. As the plans move toward the final steps in the decision process, impacts are scrutinized in increasing detail and mitigation plans are developed. In this kind of process, socioeconomic impact assessment is embedded in the planning process and continuously develops information that results in modification or revision of the project, which must then be reassessed, and so on.

In this type of an assessment process, planners and administrators may be responsible for carrying out an assessment, for participating in an assessment process as representatives of a local, State, or Federal government agency, or for evaluating assessment results. In each of these roles, the common requirement is that the planner or administrator participates in and understands the assessment process, so that the appropriate questions are addressed and so that the answers derived from the process are correctly interpreted.

As shown in Figure 5, socioeconomic assessments proceed from a description of the proposed action to an estimate of social impacts through several causally related steps. Each step focuses on a particular type of impact and is closely related to the preceding and following steps. For example, the change in employment associated with a coal development project will affect local population growth. Population growth in turn affects the demand for facilities and services, which has important fiscal implications.

The causal relationship among the steps illustrated in Figure 5 can be summarized briefly. The annual labor requirements, payroll, and local purchases generated by the proposed action cause the gross economic impact

FIGURE 5.
ORGANIZATION OF THE ANALYSIS OF IMPACTS ON THE HUMAN ENVIRONMENT



SOCIOECONOMIC IMPACT ASSESSMENTS are usually organized around these seven steps. Whereas the diagram implies the most common casual relationships between components are in a left-to-right direction, socioeconomic impacts actually occur in an iterative fashion.

Source: Mountain West Research, Inc., 1981.

within the region. This gross economic impact is spatially refined by accounting for the number of nonlocal workers attracted by the proposed action, their residential distribution and commuting patterns among communities within the region, the employment multiplier caused by local purchases generated by the proposed action and its employees, and finally, the flow of income among communities in the region due to trading relationships. Economic impact is then translated into demographic impact by accounting for the total number of nonlocal workers attracted to the various communities in the region and the family accompaniment rate for these nonlocal workers. The demographic impact will cause increased facilities and services needs, both public and private--that is, housing, schools, etc. These additional required facilities will be distributed spatially within a given community and will affect land use patterns. Next, the level of demand for public services and the spatial distribution of physical development will have local effects on the level of State/local revenues and expenditure. Finally, all of the above impacts can have social effects on both newcomers and the long-time residents of local communities.

The implementation of socioeconomic impact assessment is characterized by the chronic unavailability of data and by the fact that local economic, population, facilities, fiscal, and social conditions are dynamic and may be changing regardless of the proposed action. Consequently, the entire assessment process is laden with assumptions. The problems to be addressed in each step of the assessment process are reviewed in the following paragraphs.

Description of the Proposed Action

An accurate decription of the impact stimulus--the proposed action--is extremely important to the accuracy of the assessment process. However, impact assessment is generally required well in advance of project implementation and often before detailed work plans are formulated. Thus, the description of the proposed action is frequently based upon preliminary estimates of project scale, timing, work force, local purchases, and implementation policies. Not surprisingly, the character of the action actually implemented usually differs in many important respects from the action proposed. Numerous examples support this view. For example, the Jim Bridger Power Plant near Rock Srings, Wyoming was originally expected to consistof one unit with a peak construction work force in 1974 of 1,300 persons. In fact, two units were eventually constructed, and the work force peaked in 1973 at 3,000 workers.

Economics

Once the project work schedule has been provided, it is necessary to estimate the nonlocal portion of the work force, its family accompaniment rate, and its residential distribution among localities within commuting distance to the project site. Empirical data indicate that these parameters vary significantly from project to project. Mountain West Research, Inc., for example, surveyed 14 power plant and mining project. Nonlocal worker composition of the work force averaged 60.1 percent but varied from 97 percent to 21 percent among individual projects. Family accompaniment averaged an additional 1.14 persons per nonlocal worker but ranged from 1.87 persons to 0.21 persons per nonlocal worker on individual projects.

One approach is to estimate average relationships using empirical data. Equations incorporating these average relationships are then used in the assessment to project such things as local share of the work force, age/sex composition of the work force, etc. The allocation of in-migrating workers among several communities has been carried out by ad hoc methods, modified gravity models, and linear programming models. However, because each project and site has unique characteristics that may render those methods inappropriate, a great deal of uncertainty attends the prediction of the local labor share, its composition, and the residential distribution of in-migrating workers.

The next step in the assessment is to estimate the income earned and spent by workers. This can be done using anticipated average monthly or annual payroll information furnished by the developer, which is subject to the same errors as information about the work schedule, although the error may be less serious if average payroll is used. Of course, not all income is spent, which necessitates estimating spendable income. Nonlocal construction workers, who are temporarily working away from their homes, are likely to spend less in the area than local workers. Because data on locally spent income are highly limited, estimations of local expenditures are often very uncertain.

When the project work schedule, the local/nonlocal composition of the work force, the residential distribution on nonlocal workers, and the income earned and spent by all workers have been estimated, these direct, project-related impacts must be distributed throughout the regional economy. Three techniques are commonly used to trace impacts on the regional economy: input-output (I-O), econometric, and export base modeling. Input-output models trace the interindustry implications of changes in final demand for particular types of products that may be required by coal development projects. Econometric models focus on changes in production levels, the income induced by them, and changes in demand. Export base models focus on the relationships between employment in basic (exporting) sectors and nonbasic (for local consumption) sectors and derive multipliers that may be used to forecast the economic impacts of a basic sector change, such as the addition of a coal development facility. Each of these techniques has particular advantages and disadvantages. Consequently, a combination of the most appropriate features of each technique is often used in economic impact assessment.

Demographics

The forecast total employment impact must be translated into population impact. This is usually accomplished within a demographic submodel of the overall impact assessment model. The general approach is to forecast future population without the proposed action and then to translate the action's net employment impact into population change by determining the nonlocal (in-migrating) share of the net employment impact and assigning demographic characteristics (including families, age, education, and income) to this nonlocal share.

In estimating the demographic impact, the key question to be answered concerns the degree to which increased employment opportunities will be filled from the local labor market. Thus, an analysis of local labor supply is required. The capacity of the local labor supply to meet new employment opportunities is a function of: (1) levels and changes in unemployment rates, (2) changes in labor force participation rates, (3) migration, (4) natural increase (from births and deaths), (5) skill composition, and (6) current wage levels prevailing in the area. While the composition of the resident population can be forecast by relating present characteristics to employment through cohort survival techniques, in-migrants and their families often exhibit different characteristics. These must be explicitly accounted for in terms of age, sex, education, and labor force participation characteristics.

The final result is usually found in terms of net population increase due to migration and a natural excess of births over deaths. In the short run, the major sources of error in demographic impact assessment result from inaccurate estimates of the total employment effects of the action, together with a serious underestimation of the local labor force's share of those employment effects. In the longer run, errors in assumptions regarding the total population's vital rates, age/sex distribution, and average household size can become important.

Public Facilities and Services

Public facilities/services assessments first address the quality and use of the facilities and services in the absence of the proposed action. This is accomplished with an inventory of existing facilities and services and an analysis of planned expansions or potential for expansion. Next, the assessments project conditions that are likely to accompany the proposed action. These projections use information, generated by the economic/demographic analysis, on the characteristics of the incoming population. Finally, sets of standards are used to translate the population characteristics into demand for a particular facility or service.

This type of assessment technique has important limitations in that it does not explicitly account for spatial cost variations, the effects of excess capacity, economies or diseconomies of scale, or the effects that rapid fluctuations in demand associated with project construction may have on the cost and availability of public services/facilities. As a consequence, it is often necessary to supplement the technique with standards derived by local legislative actions and with information derived from experience in other impacted areas.

Housing

Housing impact assessments make demand and supply projections under with- and without-project conditions and evaluate their effect on the local housing market. Whereas the product of this assessment usually includes forecasts of housing deficits and/or surpluses, it may also project impacts on housing and lot prices and their consequent effects on local residents. The results of the assessment can be used to determine whether existing housing regulations are adequate to regulate new housing development in a manner that respects local desires and takes full account of existing infrastructural and physical conditions.

In spite of this seeming simplicity, present approaches have several drawbacks. Preferences for housing, both in terms of housing type and amenities, have often been confused with effective demand (ability and willingness to pay). If preferences or tastes are mistaken for effective demand, projection errors will be made. A more serious problem results from the fact that supply has not been adequately accounted for as a constraint on effective demand, with the consequence that availability effects are being mistakenly interpreted as demand parameters.

There has also been a failure to account for the effects of local government regulations and political decisions on the housing market. In addition, the availability of financing from local sources has typically been ignored as an important potential supply constraint. A further weakness of current procedures is their inability to take into account changes in the availability and price of land for housing development and changes in the price of existing housing attributable to local, short-term supply/demand conditions. Data for these variables simply do not exist. Finally, many impact assessment procedures assume a static rather than a dynamic context. Particularly with regard to construction in rural areas, in which the short-term and long-term economic/demographic effects are likely to differ markedly, it is often necessary to determine how the local housing market will change from the construction phase to the operation phase of the project. Such data are only available from surveys.

Land Use

Land use impact assessments determine the direct and indirect land use requirements of the proposed action and evaluate their compatibility with existing physical conditions and the expressed wishes and intentions of local citizens. Once this compatibility is determined, the assessment may also identify mechanisms to influence or control actual land development.

The projection of land use impacts requires, as is the case for the other steps in the assessment process, that projections without the proposed action be compared to projections with the proposed action. The without-project forecasts use the baseline economic, demographic, and facilities/services projections to determine future land requirements for new residential, commercial, and facility uses. In cases where these uses are expanding, specific consideration will also have to be given to underlying land requirements, potential development areas, and the expressed wishes of local residents with respect to the development plan for the community. Projections of land use requirements with the proposed action are usually made by estimating the direct and indirect requirements associated with the proposed action and then adding them to the baseline projections.

Land use projection techniques vary from simple procedures that base future land use needs on current standards for residential, commercial, and public facility uses to more complex land use models that try to deal with all aspects of the spatial distribution of economic and demographic activity. These models have several serious problems: they are extremely expensive, they are very complex, and the key variables on which they are based (e.g., projected land prices and availability) are often not amenable to accurate prediction.

Fiscal Effects

In fiscal impact assessment, the fundamental issue concerns the effect of a given action on the revenues and expenditures of local governmental units. In assessing those effects, fiscal assessments must address not only local revenues and expenditures, but also the project's effect on intergovernmental transfers and other sources of funds for which local governments may be eligible.

To be able to predict the magnitude of capital and operating expenditures that will be required as the result of a coal development project, it is necessary to determine the present capacity of each public facility or system and to estimate the threshold level at which increased population or economic activity will exceed those present capacities. Expenditure forecasts can then be derived by applying historical or standardized per-capita cost figures to projected population or economic growth.

The difficulties associated with the above methodology are significant. Whereas residents of impacted areas may be accustomed to a rural or small town environment, in-migrants attracted by coal development are often accustomed to a more urban lifestyle and therefore demand types and qualities of public services different from those demanded by natives. Second, per-capita delivery costs may vary with population size. When combined, these two difficulties lead to uncertain expenditure forecasts.

Revenue forecasts estimate the impact of development on State and local revenues. Coal development can be translated into revenues by forecasting the appropriate economic variables affected by coal and secondary development and then applying the appropriate formulae to derive revenues from those sources. Then another set of formulae is applied to State and Federal revenues to derive intergovernmental transfers.

The prediction of revenues is made extremely complicated by the number of economic/demographic variables on which they are based and by their sensitivity to policy variables. Policy variables are particularly important in the case of intergovernmental transfers, which are often based on Federal or State discretion and therefore are virtually impossible to forecast. As a consequence of these complications, many fiscal impact assessments have developed a range of revenue forecasts for the more important revenue sources, such as property and sales taxes, and have paid only limited attention to less significant revenue sources.

A final step in fiscal impact assessment is comparing local expenditure and revenue forecasts to derive an estimate of net fiscal impact. Detailed fiscal impact assessments make these comparisons for each jurisdiction in the impact area and give careful consideration to the timing of revenue and expenditure flows.

Social Effects

The primary objectives of social impact assessments are to determine the effects of the coal development project on the social structures and lifestyles of local communities and to determine the distribution of project-related effects among community residents. Social impact assessments usually develop descriptions of existing social structure in communities that expect impact from the project and then make projections of the social environment both with and without the project. These projections take into account the demands placed on the communities, their willingness and ability to respond, and how changes would effect particular groups and individuals. The amount and type of impact for particular groups or individuals depend on their position in the community, on project characteristics such as the type and size of the workforce, and on community characteristics such as size, social values, and past experience with other projects.

The primary difficulties associated with social impact assessment concern: (1) the multitude of exogenous factors that affect social indices of well-being and community satisfaction, and (2) the general disagreement among analysts about what comprises quality of life and how to measure and forecast it using historical values. For example, although most analysts agree that public facilities and services congestion, adverse economic effects such as inflation and rising land values, and scenic effects constitute social impacts, there is little agreement on what objective measures can be used to quantify and compare social effects under with- and without-project conditions. As a consequence, social impact assessment for coal and other resource development projects remains a very inexact science.

SOCIOECONOMIC IMPACT MONITORING

As the coal development project is undertaken and construction begins, the impact assessment methods discussed above remain useful. The assessment and planning that will have occurred during the preconstruction period will have forecasted the implications of the proposed project. However, areas of uncertainty, some of which may be very important to particular physical planning decisions, will remain. Socioeconomic impact monitoring collects data on key project and community characteristics, compares actual changes to forecast changes, identifies problem areas, and then uses the new data to revise future impact projections.

The purpose of socioeconomic monitoring is to provide local planners, administrators, and other key public and private sector decisionmakers with information that will help them anticipate and plan for project-related impacts. Consequently, to be effective, monitoring systems must be designed to provide information that is pertinent, accurate, and available far enough in advance of the impacts to allow decisionmakers time to identify problems and implement changes.

Monitoring systems typically have two components. Preoperational monitoring gathers baseline data before the project is constructed and serves as a benchmark against which operational monitoring findings can be compared. Operational monitoring identifies project-generated impacts as they change over time and analyzes their effects on various socioeconomic characteristics of the affected communities.

A preoperational socioeconomic monitoring system is essential for a successful operational monitoring program. The information gathered during the preoperational period generally includes, but is not limited to: (1) population data by community; (2) employment data by economic sector and by coal and other energy-related project; (3) housing data by type, including cost, vacancy rate, and financing data; (4) facilities and services data by jurisdiction; and (5) local government fiscal conditions by jurisdiction. These sets of socioeconomic data can be used to generate baseline and with-project forecasts and to identify and analyze impacts. They are updated regularly until the beginning of the construction period and operational monitoring, and they reflect the same systematic mechanisms of data collection, analysis, and distribution that will be used during the operational monitoring program. This type of system often necessitates formal cooperative arrangements with both local and nonlocal officials to obtain and distribute data in a consistent and timely manner.

Operational monitoring not only determines the impacts as they change over time but also allows for assessing the effectiveness of committed mitigation strategies. Operational monitoring systems maintain data on one or more local projects and on the communities and counties affected by these projects. They typically include information on project work forces, population changes, housing inventories, public facilities and services status, fiscal conditions, and other specific problems or issues regarding the resource development project(s).

Monitoring Processes

The monitoring program involves a multistep process, beginning with the program design. This requires agreement on what is to be monitored, by whom, how frequently, and in what manner. Also, the program design must incorporate answers to the following questions: (1) How and by whom is the collected information to be compiled, analyzed, and reported? (2) With what frequency are monitoring reports to be generated? One of the most important requirements of a monitoring program is that it must identify unanticipated effects, such as settlement and population growth in unexpected locations.

Once the design is reviewed and approved by information supplier and users, data collection schedules are set. This includes developing the necessary cooperative agreements with key local contacts and company representatives and identifying the details for regular and systematic data collection. The schedule ideally includes monthly updates on work force data, housing data, emergency services, health care caseloads, school enrollments and capacities, and city water and recreation information. Updates would be conducted on county employment, new businesses, public assistance programs, city sewer services, and school, county, and city expenditures. The actual monitoring reports should be compiled on a timely basis and distributed to local officials for their review. In addition, the results should be analyzed and used to update community population, housing, and facilities and services demand forecasts. This would assist in identifying significant changes that might require new mitigation programs or modifications of existing ones.

IMPLEMENTATION: MITIGATION OF IMPACTS AND PLANNING FOR CHANGE

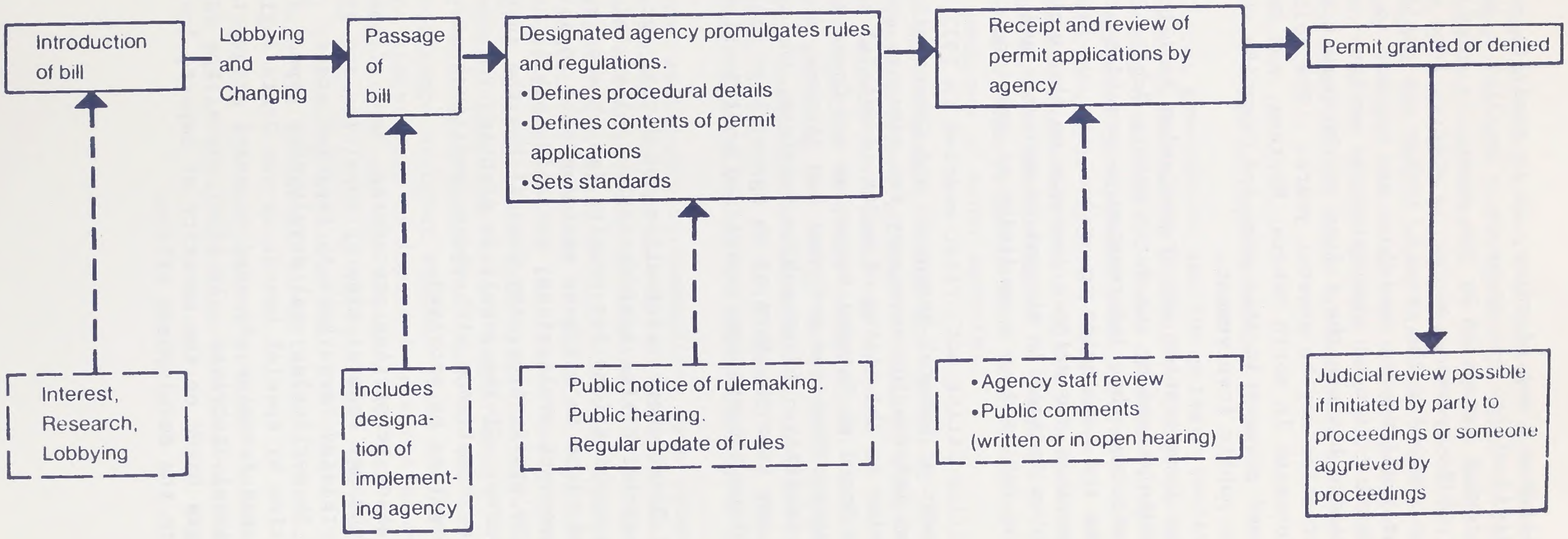
The participants in mitigation and enhancement of coal development impacts may include Federal and State agencies as well as local communities and the energy developers. The following discussion provides a brief overview of Western coal States' legislative responses to coal and energy development and then outlines Federal, State, local, and private roles in developing and implementing mitigation programs.

Legislative Responses To Impact

The State legislatures in several Western energy States have implemented regulatory procedures designed to govern the application and review of permits required for the construction of coal facilities. In most cases, these procedures meet or exceed Federal minimum standards and require significant public and local government participation.

As shown in Figure 6, most regulatory programs begin with introduction of a bill in the State legislature, which results in designation of a new or existing agency to implement a regulatory law. The responsible agency then formulates rules and regulations for implementing the legislation. This phase of the regulatory process is critical, because it defines procedural details, the content of permit applications, and, in some cases, sets of specific standards for granting permits.

FIGURE 6.
OVERVIEW OF STATE REGULATORY PROCESS.


Introduction of bill
Lobbying and Changing
Passage of bill
Designated agency promulgates rules and regulations.
•Defines procedural details
•Defines contents of permit applications
•Sets standards
Receipt and review of permit applications by agency
Permit granted or denied
Interest, Research, Lobbying
Includes designation of implementing agency
Public notice of rulemaking.
Public hearing.
Regular update of rules
•Agency staff review
•Public comments (written or in open hearing)
Judicial review possible if initiated by party to proceedings or someone aggrieved by proceedings

Source: Mountain West Research, Inc.

Once the agency establishes a set of rules, it is ready to consider permit applications from individual project sponsors. Usually, a permit application containing all the material requested by the agency is submitted to the agency for staff review and public comment, either in written form or in an open hearing. The agencies reexamine the permit, review the public comments, and make a decision. Nearly all agency decisions are subject to review by the courts. Because judicial review of administrative actions can be extremely time-consuming, the period between the filing of the permit application and commencement of construction may be several years. The following paragraphs examine the permit processes in North Dakota, Montana, and Wyoming, three States that have assumed primacy in this area and identify the opportunities they provide for local public involvement.

The North Dakota Energy Conservation and Transmission Facility Siting Act, enacted in 1975, is administered by the North Dakota Public Service Commission. The Act requires that information be provided at the time of application, authorizes the commission to conduct its own impact studies, and provides for public hearings and written comments on the application. The Act authorizes the commission to specify mitigation measures and impact monitoring procedures that must be followed as a condition of granting the permit.

The Montana Major Facility Siting Act, first enacted in 1973, is administered by the State's Department of Natural Resources and Conservation. It was designed to ensure that information necessary for adequate community planning efforts be provided prior to the siting of major industrial facilities. The Act specifies that the Board of Natural Resources and Conservation can spend up to 2 years reviewing applications and then can approve, deny, or approve with modification the facility. After public hearings, the board reaches a final decision, which may take the form of an approval or denial of the application or approval contingent upon specified modifications and/or conditions.

The Wyoming Industrial Development Information and Siting Act, enacted in 1975, created the Industrial Siting Administration and an Industrial Siting Council, which reviews applications for permits (which must contain information on the project and plans to mitigate socioeconomic impacts, among other things), conducts independent evaluations, and holds public hearings. In denying or approving the application, the Council has the authority to specify impact mitigation measures. If the permit is granted, the council also has the authority to monitor compliance with these conditions and to require that impact monitoring information be provided.

In addition to establishing permitting procedures, most of the States have developed programs to channel Federal mineral royalties and severance, sales, and other coal-project-related taxes back to impacted areas. Generally, the revenues are allocated to particular coal development impact funds and then distributed to communities by special boards or the State legislative. In some cases, preestablished formulas are used to award grants to local counties, towns, and school districts. In other cases, the States adminsiter grants, loans, or pledges based on the severity of impact, local need for funds, and commitment to the development effort.

Colorado has established several trust and impact funds that distribute shares of Federal mineral royalties and State severance taxes to impacted local governments. The funds are administered by the Joint Budget Committee of the State legislature and by the State's Department of Local Affairs. Montana's impact assistance program has eatablished the Coal Board, which uses coal severance tax revenues to supplement Federal and industry monies in aiding impacted areas. Other Western energy States have instituted similar programs for distributing State and Federal funds to impacted areas.

Roles in Implementation Process

Federal, State, and local governments and the private sector have assumed a wide variety of roles in implementing mitigation programs and planning for change in energy-impacted communities. Most of these programs have been designed to provide affected communities with information on energy projects orto administer technical and/or financial assistance in helping them plan for the housing and facilities/services needs of rapidly growing populations. In some cases, the programs have been designed to complement those of other agencies. In other cases, the programs have been designed to offset perceived deficiencies in the programs of other agencies.

Through the National Environmental Policy Act (NEPA) of 1969 and its requirement that an Environmental Impact Statement (EIS) be prepared for most large energy projects, the Federal government has assumed an important role as a provider of impact information to local communities. Other Federal roles in the mitigation of and planning for energy development impacts include Housing and Urban Development, Econmomic Development Administration, and Farmers' Home Administration programs and grants to help communities construct capital facilities and develop their planning and growth management abilities.

These forms of Federal assistance to communities have often come under State and local criticism because they either do not provide the right kind of impact information on a timely basis or because they do not make funds available to communities with small populations. As a result, several Western energy States have instituted programs or policies more carefully tailored to their own needs. Several States have instituted energy project siting processes that require socioeconomic information in addition to that required by NEPA. In many cases, their information requirements have been designed around the needs of local decisionmakers. Most of the Western energy States have also imposed severance or other special taxes on the energy industry, a portion of which are distributed to impacted communities on the basis of need. This type of financial assistance may be earmarked for specific capital-projects or for more general planning activities. The assistance can be particularly useful in solving problems that are created when energy projects and their impacts occur in different local taxing jurisdictions.

Local government's role in the development process includes the construction and operation of the public facilities and services needed by new members of the population and the direction of private sector growth through use of comprehensive plans, land use controls, and building permit systems. Their participation in the process can begin in the review of impact statements required by State or Federal guidelines and continue with more specific programs and policies to influence the development process so that it will conform as closely as possible with local goals and objectives.

The private sector's participation in energy-related growth includes both the specific actions of the energy developer and the market response to local needs for additional housing and commercial establishments. The role of the energy developer can range from complete provision of a company town, such as Colstrip, Montana, to provision of a particular type of facility or service, as is discussed in the following paragraphs. Other private sector roles can range from housing developers participating in the local planning process to a particular entrepreneur establishing a new business to take advantage of an opportunity presented by energy-related population or economic growth.

Mitigation and enhancement strategies have two dimensions, the first of which is the establishment of a participatory (and ideally collaborative) relationship between the coal development project sponsor and local communities. This relationship typically includes provision of both information about the project and technical assistance that will aid in the planning process and identify ways to address potential problems. The second dimension includes more specific actions that deal with particular types of socioeconomic problems.

Public involvement programs require project sponsor and community participation and are designed to obtain and disseminate information about manpower loadings, schedules, population forecasts, and potential impacts and mitigation measures. The public involvement program can be administered through meetings and workshops, media coverage, and newsletters. Information about residents' reactions to particular issues can be obtained through questionnaires or key informant interviews.

Public involvement can also entail project sponsor participation in the local planning process. This type of involvement establishes ongoing relationships with local planners and officials. It can include technical assistance in areas such as population forecasting and help in identifying potential sources of funding to meet the financial needs generated by the growth.

Perhaps the best known example of a general sponsor involvement program is the Inter-Industry Technical Assistance Team (ITAT), which was formed by several utility, gas, and coal companies in 1977 to monitor socioeconomic impact in Mercer County, North Dakota. Other examples include the Southwest Wyoming Industrial Association in Sweetwater County, Wyoming, the Wyo-Mont Industrial Association in Sheridan, Wyoming, and the Front-End Funding Committee in Craig, Colorado.

The mitigation and enhancement measures that can be used to deal with more specific types of socioeconomic impact have both advantages and disadvantages. During the construction period, project sponsors can reduce the number of new residents and their temporary demand for housing and public facilities and services by instituting a "local hire" policy. Such policies are enhanced when labor requirements, potentially relevant training programs, and other information or tools are identified well before construction begins. These actions provide for good public relations and result in a more stable work force, but they have the disadvantage of drawing employees from other sectors of the local economy and thereby increasing the possibility of labor shortages in those sectors.

The project sponsors can also alleviate problems associated with the provision of temporary housing and facilities and services by scheduling construction work forces to minimize the labor force peak. The primary disadvantage of this measure is its tendency to lengthen the construction period, which may have adverse social effects on local communities.

Most of the topics associated with the consequences of population change are discussed later in this chapter. The purpose here is to point out that one of the most important demographic mitigation actions that can be taken is to closely monitor the progress of the proposed action as it occurs. Various key assumptions of the demographic analysis will become open to evaluation as the project actually begins. Therefore, it is very important that variables like the size of the construction force, its local/nonlocal composition, expansion in nonbasic employment, etc., be watched closely and that they be compared to projected values so that the projections can be modified as appropriate.

Facilities/services mitigation measures can be implemented by the project sponsor, by local or State public agencies, or by more than one of these entities working in concert. Mitigation strategies of general facilities or services often include project sponsor provision of engineering and technical assistance to aid in the design and cost of needed facilities. This measure helps avoid crisis situations that might arise because of strained local response capacities, but it may be viewed as an interference with community responsibility. Other measures that have been used on occasion include the project sponsor's allowing use of heavy equipment for facility construction or donating capital or operating equipment to local government agencies. These measures can insure the timely provision of needed facilities and improve the project sponsor's local public relations, but they have the disadvantage of making local governments depend on the sponsor rather than solving their own problems.

To the extent that they cannot be provided by local school districts, land for expansion, temporary classrooms, and school buses can be provided by the project sponsor responsible for the population influx. These facilities can be donated or purchased by the project sponsor and then leased back to the school districts. These types of mitigation measures relieve school districts of the expense for facilities that are useful for only a short time, but they do foster dependency on the project sponsor.

In some cases, where taxes on the coal development project may accrue to one school district but demand impact to another, consolidation of school districts may be appropriate. This type of action would distribute future tax revenues to needs districts but could be a highly controversial political issue for other reasons.

In addition to donating or financing capital health facilities, project sponsors and public agencies may want to institute or support impacted communities' recruitment programs for doctors, dentists, and other health professionals. This assistance would require a short-term capital outlay but, if successful, would provide a long-term service that would benefit the local communities and help the project sponsor to attract workers as well.

Project sponsors can minimize traffic congestion on roads between communities and the project site by providing buses or supporting car or van pools for workers. In addition, the project sponsor could stagger working hours to lower peak traffic loads or assist in upgrading and maintaining roads that serve the mine and plant sites. All of these actions can be expected to lessen congestion and accidents, but they may also inconvenience both the project sponsor and the individual workers who are forced to revise their work schedules.

Project sponsors and government agencies can mitigate outdoor recreational impacts by identifying appropriate outdoor recreation activities and areas for workers and by providing worker education programs on area hunting and fishing laws, the use of public lands, and respect for private lands. In addition, project sponsors who control land appropriate for recreational use may want to develop water recreation sites or upland bird/waterfown habitat areas. Urban recreation impacts can be mitigated by provision of indoor recreation facilities at construction camps or through the encouragement of mandatory park dedications in new subdivisions.

A major problem in housing and land use mitigation is that there is no one agency which has complete responsibility for resolving the impact issues. Instead, there is usually a host of actors, both public and private, involved in the provision of housing and land use planning. In the case of housing mitigation, the number of actors involved leads to a wide range of impact strategies. These strategies include provision of a construction camp or other project-sponsor-built housing and provision of information and/or technical assistance to local and nonlocal builders and developers who could build housing in the impacted areas. On the financial side, project sponsors may be able to stimulate housing development by providing builders and developers with financial or rental occupancy guarantees and by cosigning construction loans. Finally, the project sponsor or a government agency can help workers afford new housing by assisting them with low interest loans or by assisting local lending institutions in attaining financing to make loans to prospective buyers.

The critical ingredient that minimizes land use impacts is community commitment and involvement in the land use planning process. Steps in this process include determination of goals, establishing alternatives and setting priorities, planning physical facilities, and determining ways to finance them. When many local residents are active in this process, it is easier for communities to control the adverse consequences of development and to simultaneously shape development so that the net effect is enhancement of the community.

There are several strategies which can be pursued to mitigate negative fiscal impacts. First, ways to increase the revenues resulting from the proposed action can be explored. This might include, for example, increasing the hookup fees for utility services to more nearly reflect the costs of providing additional utility services or having the developer of the proposed action contribute directly to help provide a specific public service or facility, such as improving a county road from the community to the construction site. Second, additional sources of local revenue that are politically acceptable may be available, such as increasing the local sales tax. Third, there may be ways in which jurisdictions receiving revenues as a result of the proposed action (e.g., county governments) can share revenue with jurisdictions bearing disproportionate costs (e.g., cities or towns). This sharing can sometimes be implemented directly through formal agreements among the jurisdictions concerned, or indirectly by having the county assume responsibility for providing services that it had not previously provided (e.g., law enforcement services). Finally, it may be possible to obtain help from State or Federal programs.

The identification and evaluation of social impacts leads to a mitigation process in which decisionmakers seek to enhance positive impacts and minimize negative impacts. Information generated through the impact assessment process facilitates the planning process as issues and options are identified. Depending on the size and nature of the project, the degree of public support or opposition, and the type and kinds of projected social impacts, it is desirable to continue some level of public involvement throughout the mitigation process. In addition, an ongoing information exchange program may be established, which functions after the official study is completed to ensure that decisionmakers continue to have the information necessary for knowledgeable planning.

In terms of specific social mitigation measures, it is important to recognize the uncertainty that surrounds energy development in the western energy States. Because the numerous coal and other energy-related activities that have been proposed in the region typically have several alternatives, actions are often subject to delay, and many residents are often skeptical about a particular project until actual construction begins. For this reason, once it is decided to move forward with a project, it is important for the project sponsor to convince people of its reality so that they can begin to take the necessary steps to deal with growth. A positive action on the sponsor's part, such as donating funds for planning services or setting up a local office, can help convince people of the reality of the project. Other social mitigation strategies include workshops that address methods of dealing with growth-related, temporary activities and other types of forums that identify and discuss growth-related social problems.

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FEDERAL LAND MANAGEMENT IN THE COAL AREAS OF THE NORTHERN GREAT PLAINS:

A RANCHER'S PERSPECTIVE

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LIST OF ACRONYMS

BIA - Bureau of Indian Affairs
EIS - Environmental Impact Statement
EPA - Environmental Protection Agency
KRCRA - Known Recoverable Coal Resource Area
MFP - Management Framework Plan
MPC - Montana Power Company
NPRC - Northern Plains Resource Council
OSHA - Occupational Safety and Health Act
OSM - Office of Surface Mining
TEEA - Technical Examination and Environmental Assessment
TSP - Total Suspended Particulates

I first became concerned in the mid-1960s about the conflicts between ranching and coal development and the role played by government agencies between these two industries.

In 1960, the Montana Power Company (MPC) bought Colstrip, Montana, from the Northern Pacific Railroad Company. This was probably the first indication to me, and the other ranchers in the Colstrip community, that there was at least an interest in reviving the coal mining industry. At the time we ranchers in the Colstrip area were mildly interested and mildly favorable towards a resumption of mining. We had all grown up and gone to school in Colstrip and, for the most part, welcomed the increase in social and economic activity that a resumption of mining represented.

Colstrip had always been a company town but, for the most part, it was responsibly run by the Northwest Improvement Company (a subsidiary of the Northern Pacific) and did not suffer from the "company town image" so prevalent in other company-owned mining towns.

We ranchers felt that the Montana Power Company would be at least as good a neighbor as the Northern Pacific had been. We assumed there would be voluntary efforts made to reclaim the mined land and that the MPC would assume the most obvious community economic costs that their activities created. These rosy prospects were not realized. Our repeated attempts to open lines of communication with those making decisions about our community were rebuffed, ignored, and rejected.

About this same time, representatives from Consolidation Coal Company, Peabody, and a batch of high-pressure lease hounds began making noises and moves to establish what they refer to as "position" in the coal business. The coal company land agents dispatched into the hinterlands were quite competent at their jobs. Depending upon the signals they received from often-reluctant landowners, they had a whole assortment of approaches in their repertoire. If the landowner appeared in an economic bind (by complaining about low agricultural prices during the "coffee-at-the-kitchen-table-softening-up" phase, or by obviously living beyond their means) the "eventual-bonanza" approach was taken. If the ranch owners were old, the "retire-in-Palm Beach" approach was used. The intimidated were threatened. The naive misled. The greedy quickly satisfied.

The lease hounds had several advantages. The most obvious was the existence of the split surface and coal ownership. Another was the cultural reluctance for ranchers to compare notes or obtusely ask their neighbors about the overtures or threats from the company reps or speculators. Guilt, patriotism, fear, greed--all of these emotions were played upon extensively and sometimes effectively.

A poem that I wrote during the early 1970s gives some insight into the arguments and the tactics of the coal companies (and my reaction to it):

CRISIS

Get the coal out, with a tumult and shout.
Yes, tear it out of the ground.
There's a crisis to smite and cities to light.
There's billions of tons to be found.
And when coal is burned great wheels will be turned.
And a shaft from the wheels turns the earth.
It's simple you see (or so they tell me)
As they ravage the land of my birth.

Damn pristine air! There's water to spare!
We'll lower your taxes for you.
We'll pave all your roads. Help shoulder your loads.
Their cajoling beats a tatoo.
We'll build swimming pools and public schools--
Build an empire upon your Plains.
Just climb in with us, on our omnibus.
Eat our truffles and drink our champagnes.

Don't fret for the grass. If our plans come to pass,
You'll have more than you've ever seen.
For we can "reclaim." (At least that's our aim.)
We'll improve what once was pristine.
But, if you feel doubt, then we'll buy you out
For more money than you've ever seen!
Enjoy wealth to the hilt. To assuage your guilt,
Wash in dollars if you still feel unclean.

In times such as these, in our energy squeeze,
You must try the "big picture" to see.
If untempted by booty, then think of your duty.
If you're selfless, then you must agree:
Our Country must grow or the grey faceless foe
Will surely stalk o'er our grave.
For Growth made us great. It must not abate.
It's no monster, you see, Growth's our slave.

We'll win in a rout, if we get the coal out.
We'll all be the winners, you see.
We'll not freeze in the dark. We'll continue our lark.
And coal--good black coal--holds the Key.

On their shrill voices go. Drifting, sifting little snow.
I resist them with all of my might.
For their cloying, sweet song is grievously wrong.
Deep within me, I know that I'm right.

© 1979 by Wallace McRae
It's Just Grass and Water

The companies also made some mistakes. Often they assumed that no one in his right mind really liked living (and trying to make a living) in the Northern Plains. The company "bird dogs" often mistook hospitality for acquiescence, or stupidity. Their obvious insincerity was also a burden for them. Even though most of them didn't know which end of a cow ate grass, they all knew (or thought they did) the proper seasonal questions: "How's your (depending on the time of year): 1. winter feed? 2. calving going? 3. crop? 4. hay crop? 5. grass holding out? 6. contracting look? 7. grain yields? 8. calf weights? 9. conception rates?" and back to number one.

An acquired talent that you quickly develop in the country is the ability to judge a vehicle's occupant(s) from the time they make it from their mode of transportation, past the barking dog, to your front door. You learn to quickly "work the herd" mentally and put visitors in to the proper "cuts." Confused tourists; cattle buyers; feed, implement and veterinary supply salesmen; representatives of religious sects; and prospective horse buyers can usually be discerned. But lease hounds and energy company executives are usually even easier. A rented, clean, four-wheel-drive van is the first clue. If it is driven by a pseudo-westerner or a pseudo-outdoorsman, the probability is increased considerably. If the guy has a couple of flunkies or arms bearers--more evidence. Rolled-up maps and briefcases (nearly certain), and if when you open the door he says with a Colorado or Texas accent, "Mr. McRae" (who the hell else did he expect to be answering my door?), the probability approaches one.

So the country was suddenly filled with clean, white four-wheel-drive vehicles driven by people who were uncomfortable when waved at. What were we going to do? What were our rights? What were our obligations? What opportunities were there? What would happen to our communities, our non-coal resources, our lifestyle and our culture? Who would help us? Or save us?

Partially out of naivety and partly because of the reassuring rhetoric coming from the coal industry, we felt that the coal-caused depredations of the past would not be repeated in our area. Surely the companies and the governmental agencies were more responsible than they had been in the past.

> Frank Premack, the president of Westmoreland Resources, said, "Coal is a dirty thing, and no amount of rich prose can disguise that, but we are a new breed, with a grey hat, hopefully getting whiter; a new breed of miners who is aware environmentally. Not like the old eastern operators. They did a bad job; some were unscrupulous and developed a reputation for being irresponsible. . . I'm more sensitive to environmental constraints and to people . . ." (Minneapolis Tribune 1973).

> A Gulf Oil official in a letter to a Montana resident was hardly reassuring when he candidly said, "The disposition of these deposits (of coal) will be determined by the economic and social implication of some 150 million megalopolitans located to the East . . . Providing we still have a representative form of government, then

> the West's minimal population, with their opinions, hopes, desires and dreams about certain tracts of real estate, will be of little or, more probably, of no consequence to the voting majority. . ." (Minneapolis Tribune 1973).
>
> In July of 1968, the first trainload of coal left Colstrip for the new Montana Power Company Corette Power Plant at Billings. The Billings Gazette, in reporting this event, commented that "Conservationists . . .are critical of the 'spoil banks' at the coal mines," but (Montana Power) replies that the land is marginal anyway." Uuno M. Sahinen of the Montana Bureau of Mines remarked that the public really shouldn't complain about mining companies that, in their words, "despoil the land." After all, he said, less than twenty-five square miles of this large state have been dug up by mining.
>
> "And," he added, "If they really want to quibble about it--look at that landscape over there." He gestured toward the red-topped buttes, fringed with ponderosa pine trees marching back into the distance in jagged rows. "According to some standards a mining company who left land looking like that could be prosecuted."
>
> Last Stand at Rosebud Creek
> by Michael Parfit (1980)
> p. 59-60

Meanwhile back at the ranch, Peabody was really putting the heat on my neighbors and me. I had reluctantly given Peabody core drilling rights on my ranch. They had already received permission to drill on the ranch just to the west of me and wanted to "follow up a vein into my place to see how far it went." I knew that a north-south drainage (Miller Creek) would bisect the vein so that they probably would not go very far before the coal vein was eroded away. The Peabody agents carefully pointed out to me that I was legally bound to let them in because the coal was owned by either the government or Burlington Northern. The agents also suggested that I call a lawyer for advice on my rights. Much later, I discovered that Peabody had retained the law firm that I had used for years. "Our" lawyer told me that I "probably" could not prevent the core drilling, but that I could charge damages. I felt that the damages on one section would be pretty small so I let them in.

About 6 months later, they were still drilling on the east side of the ranch, having drilled clear across it. I specifically told them not to use any water to drill with, except from live streams; but they used some reservoir water. The coal holes were inadequately plugged. They drained the oil out of their trucks on my land and littered it with assorted junk.

Over a year after the drilling started they were still milling around on the outfit, "surveying." I had had it. So after a nasty confrontation, I ran the whole rat pack off my land. A vice-president from St. Louis showed up in his rented van with his maps and a briefcase and we had a rather interesting discussion in which I learned that "probably" I wasn't obligated to give access in the first place. The Peabody vice-president, since I wouldn't let them continue their surveying, allowed as how I was "unreasonable," and I guess I have remained "unreasonable" over coal development to this day.

Some questions that came up during this time were: Where is "the government" if this is partially "government" coal? Does the government require a permit before private exploration takes place? Does the government have any obligations to the owner of the surface over "its" coal? As nearly as I can figure out, even though the BLM knew about the extensive drilling being done, it required no permits, no bonding, took no responsibility and really didn't give a damn because dumb old Peabody was gathering important data for them, free.

About this same time, the Montana State Agricultural Experiment Station was beginning "research" on mined land reclamation. The "team leader" of the research unit was trucking around the country on the service club circuit showing a slick slide presentation of how mined land at Colstrip was reclaiming itself. Later, when we ranchers criticized the pro-industry bias of the research and especially that of the "team leader," he said that since we weren't funding any research (as were the coal companies) then we could surely not bitch.

In 1969, a neighbor and I went to the Montana Stockgrowers Convention with a resolution asking the legislature to enact a strip mine reclamation act. An official of the State Bureau of Mines and Geology bitterly opposed our resolution and only agreed to drop his opposition when he convinced himself that even if the resolution passed, the legislature probably wouldn't pass a bill that would impede coal development in any way.

Somewhat later, the head of the air quality division of the Montana Department of Health publicly said that a feedlot builder needed a permit "before he dug the first post hole" while under the same law, Montana Power could build Colstrip Units I and II, up until the boilers were installed, without a permit.

In 1971, the North Central Power Study was released. Although after the furor subsequent to its release it was hard to find anyone who had a hand in its writing, it was a joint Federal agency-electric utility product. The North Central Power Study (BLM 1971) proposed: (1) Producing 50,000 megawatts of electricity (the Corette Plant was a 180-mW plant). (2) Thousands of miles of 500 and 765 kilovolt lines (the largest in Montana at the time was a 230-kV line). (3) Twenty-one power plants in Montana (out of a total of 41). (4) Some 855,000 acre-feet of cooling water (more than half of New York City's annual consumption) and a plethora of dams, aqueducts, pumps, and pipelines. (5) Strip mining of 210 million tons of coal from 10 to 30 square miles per year. (6) Construction of coal gasification and liquefaction plants that would consume an additional 2.6 million acre-feet a year. (7) Mile-wide transmission line corridors for 8,000 miles of transmission lines. (8) Population increase of at least 500,000 in the area.

No other document has so frightened and angered agricultural people in the Northern Great Plains as has the North Central Power Study. The government which we hoped might control and direct reasonable coal development played a very important and integral part in developing and promoting this proposed holocaust.

We ranchers asked ourselves some hard questions. Can the land be reclaimed? What does strip mining do to the aquifers? Who will pay the social and economic costs? How much water is 855,000 or 3.455 million acre-feet? Can our surface rights be preempted for strip mining? Does the nation really need Western coal? This much Western coal? What will this level of development do to the air and subsequently to our cattle, our crops and our families' health? What are the alternatives? Is there really an "energy crisis?"

It appeared that our existing agricultural groups were not going to take the bull by the horns and answer any of the questions. The Montana Stockgrowers Association that passed the reclamation resolution was uncomfortable in taking "controversial stands" on "environmentalist's issues." The Federal agencies, like the Department of the Interior, had violated their own rules and laws while promoting leasing the Northern Cheyenne's coal, and were rather than a help part of the problem since they helped sponsor, fund and promote the North Central Power Study.

In an attempt to find some answers and form some solutions we formed the Northern Plains Resource Council (NPRC).

We thought that before we became too involved we should find out how possible the horrors outlined in the North Central Power Study could be. We tried to find out how much coal and/or surface was already in the hands of the coal companies. We went to the BLM. At first, we were suspicious, then finally amazed that the BLM had no idea of the quantity or location of coal leasing or surface acquisition. We did our own research. Hundreds of thousands of acres and billions of tons had already been committed to such major corporations as: Gulf, Sun Oil, Amax, Hunt Oil, Pacific Power and Light, Shell, Cities Services, Exxon, Chevron, Atlantic Richfield, Kerr-McGee, Mobil, Reynolds Metals, Peabody, North American Coal, Kewanee Oil, Kemmerer Coal, Occidental, and others, including Montana Power.

The BLM finally came to us and asked if they could see our coal resource figures (we thought initially, to check out the accuracy of our numbers), because they still had no idea of what the numbers, or who the players, might be. We gave them the numbers and the players.

Some time after this, the BLM attempted to prevent landowners from finding out whether or not the coal under our surface had been "nominated" for leasing and which companies were nominating the public coal under our surface. After extended legal maneuvering, the whole secret "nomination process" was thrown out.

Throughout the 1970s, a lot of dynamic things were happening at both the State and Federal level: The Montana Water Use Act, the Yellowstone Moratorium, the environmental policy acts, clean air acts, reclamation acts, the Coal Severance Tax Act, the Major Facilities Siting Act, and the Strip Mine Act. These significant congressional and legislative actions were passed over the anguished cries of the industry. But while not prohibiting or unduly restricting coal development, they were a clear signal that coal development was no longer going to be conducted in an irresponsible, rip-and-run manner.

Despite the frequent confrontations between the coal industry and the NPRC, a degree of cautious respect has developed between the two entities. This is especially evident in the area of mined reclamation. The companies are now taking pride in some of the things we, through legislation, forced them to do. Retention and direct reapplication of topsoil (as opposed to stockpiling) are examples. A voluntarily reconstructed drainage in Area A at Colstrip has impressed us. Also, because of the attention we focused on Colstrip, the town is a much more pleasant, attractive and comfortable place to live than it would have been if the companies involved had not felt compelled to devote a lot of thought, effort, and money to the planning and construction of the town.

There is a nearly unanimous perception among ranchers in the West that coal-oriented industrialization would have serious negative social ramifications for their "cowboy culture." Even one of the most vocal rancher proponents of coal development acknowledged his cultural reservations when he stated: "Sometimes I wish I didn't have any coal, then I wouldn't have to make a decision. But the problem is I do have it. We cherish this life very much and I hate to see it change." (Mark Nance, Birney rancher, Minneapolis Tribune, December 2, 1973.)

Jobes and Parsons (1974), in their analysis of attitudes in the Birney-Decker study area, said:

> Cowboy culture, a term descriptive of how local inhabitants perceive themselves . . . is a fusion of a recent history of cattle drives and battle(s) against elements and hostile natives. Although modern technology has changed the methods of raising cattle . . . many of the social interactional and organizational characteristics of the social system are preserved. (Further) many of the inhabitants feel cowboy culture constitutes a desirable way of life which can only be lived in an area like the Decker-Birney area.

Just as there is a consensus in the ranching community that coal development would have serious negative social consequences, there is also nearly complete agreement that coal development would have positive short-term economic effects. The disagreements on coal development within the ranching community are over: (a) short-term versus long-term economics; (b) short-term economic benefits versus (certain) negative social costs; and (c) short-term economic benefits versus probable permanent cultural losses. It is probably initially surprising to discover that the most outspoken agricultural boosters of coal development are those who would seem to benefit the least: They are older, politically more conservative, and, for the most part, in better financial shape than their agricultural anti-development opponents. But should this be surprising? I think not.

Since ranchers tend to be politically conservative, they have more faith in the coal industry being responsible "neighbors" than they do in the governmental agencies' ability to force the coal industry to be responsible. Most of them suffered through the thirties, then during the next three decades they made some money. They are frustrated by recent agricultural prices and operating costs and do not want to reduce their economic standard of living so tend to look with favor on the injection of the outside capital into their Levi pockets. Finally, they probably subconsciously feel that they will not be around to suffer through the inevitable bust and, therefore, might as well enjoy the boom.

If my hypothesis about why a conservative, economically secure, older rancher might be in favor of coal development is correct, then logic would dictate that the younger, poorer, more liberal ranchers would be more inclined to oppose development. The rancher opponent probably has received more years of formal education, has traveled more extensively, is better acquainted with industrial and urban lifestyles, has never suffered from real poverty, is more critical of corporate responsibility, and knows that he will probably live to suffer through the eventual socioeconomic bust period after coal development has run its course.

I should probably state that although I have described the two ranching camps somewhat specifically in black and white (young-old, wealthy-poor, conservative-liberal) terms, there are vast exceptions to this general rule. Not enough, however, to render the rough lumping inaccurate, I believe.

There are additional dangers in my somewhat simplistic hypothesis. One, it tends to ignore the uncommitted, unconcerned, and uninformed. Ranchers who fall into this gray area exist but probably in fewer numbers than one would imagine. Another danger is to assume that the "pro" and "anti" camps are numerically or proportionately roughly equal within the agricultural community. As Jobes and Parson (1974) found after extensive ethnographic research in Rosebud County, Montana: "The majority of ranchers in southeastern Montana . . . are against all-out coal and energy development and would really like to see the coal people go away forever."

One feeling that is shared by both proponents and opponents of the coal development is a distrust of governmental agencies--especially Federal agencies. There is an old joke that regularly is revived in ranching circles. The three biggest lies in the world are: "This horse I've got for sale never bucked a jump in his life"; "Your check is in the mail"; and "I'm from the government, and I'm here to help you."

The Montana Agricultural Experiment Station, Montana Department of State Lands, Montana Department of Health and Environmental Sciences, Office of Surface Mining (OSM), and to a lesser degree, the Environmenatl Protection Agency (EPA) have in many cases proved to be equitable and constructive in their role as arbitrators and catalysts between the energy companies and the NPRC.

What about the BLM? It has grown from the bumbling incompetent that had no idea how many acres or how much coal had been dedicated to development into a classic outspoken lackey and instrument of the coal industry. "Some circumstantial evidence is very strong," said Thoreau, "as when you find a trout in the milk." In the 1970s, we found when examining the BLM's milk, not just a trout, but schools of ichthyological intrigue and, with the anointing and installation of Secretary of the Interior Watt, a dairy that looks like Jaws III.

While the Occupational Health and Safety Act (OSHA), the Bureau of Indian Affairs (BIA), and the Army Corps of Engineers are routinely criticized for high-handed ineptness, relatively few ranchers have had direct dealings with these agencies, so their complaints are probably more rhetorical than substantive. Nearly every rancher, however, has had occasion to deal with the BLM, and the experience has nearly always been unfortunate. Whether the question has been recreation access, predators, prairie dogs, grazing leases, "wild" horses, or anything else, the rancher knows that in the end he is going to lose. This is not rhetoric. This is not speculation. This is a fact, and it is especially true in any confrontation between agricultural interests and coal companies. Agriculture always loses if the BLM is the referee in the "cows or crops vs coal" game.

Let me list some indications of pro-coal industry (and anti-agricultural) bias by the BLM:

1. The BLM continues to recommend more and more public coal for lease and sale to energy companies despite an obvious lack of demand. This is an irresponsible granting of a public property to private corporations at a time when that public property is at a low value.

2. The BLM, apparently under pressure from the Secretary of the Interior, is backing away from the "diligence" requirement in the Federal Coal Leasing Regulations, thereby encouraging further coal industry speculation.

3. The BLM continues to lease Federal coal in the West despite the fact that surface reclamation (or revegetation as legally required) is unproven.

4. Despite laws that require the reconstruction of mined aquifers, the BLM continues to ignore these laws and even acknowledges that these aquifers will be destroyed.

5. The BLM consistently ignores the long-term negative social implications of mining.

6. The BLM consistently ignores the long-term negative economic impacts of leasing while pointing out the positive short-term economic benefits in glowing terms.

7. The BLM, in its decision of where coal is to be leased, depends completely, it appears, on where industry wants to mine. It refuses to acknowledge that factors should be considerd other than industry economics.

8. Despite statutory guarantees of surface owner consent, the BLM consistently ignores surface owners' opinions and consent.

9. The BLM consistently refuses to examine the cumulative negative impact of coal development upon agriculture.

To prevent my contentions being dismissed as either pettiness or paranoia (The good news is that we opponents of coal development are not paranoid. The bad news is that the BLM and the energy companies really are out to get us.), I will give examples of these claims:

1. The BLM continues to lease public coal despite a lack of demand.

In Montana alone there is a 20-million-ton-per-year excess capacity in existing mines. The Big Sky and Absaloka mines are operating at minimum capacity. Western Energy laid off 70 miners in 1980. Decker is suing one of its Midwest customers for not taking the minimum amount of coal that is called for in their contract. Montco cannot find a buyer for the coal in its proposed mine despite desperate efforts to find one. Despite all of this it appears that the BLM is going to offer an additional 2.2 billion tons to be leased despite the fact that existing leases are either not being developed or mined at anywhere near capacity.

2. The BLM is backing away from the "due diligence" requirement under the Federal Coal Leasing Regulations.

The diligence requirement was instituted under the amendments to the Mineral Leasing Act to prevent industry from speculating on Federal coal leases and to encourage industry to develop mines on Federal leases. I attended a coal leasing hearing in 1981 in Billings where a BLM official said that the coal industry could be sure that the new administration would make every effort to cut red tape, such as being "more flexible" in enforcing the diligence clause. At the time, I imagined that the BLM was simply being told by the Secretary of the Interior to ignore the regulation, but it now appears that the regulation will be detoothed by a broad rewriting of the rules and guidelines under the Act. So the Department of the Interior and the BLM will not only allow industry speculation but apparently will encourage it.

3. The BLM continues to lease coal despite the fact that surface reclamation is unproven.

In the only independent appraisal of the success of surface reclamation conducted to date in the West (Wiener 1980), the results are not particularly encouraging. Among the study's findings are: "If the 13 western surface coal mining companies surveyed . . . have anything in common in their reclamation programs, it is this:

> *All say they plan to reclaim fully--return to its former uses and productivity--the land they are disturbing.
>
> *None has yet proved that successful reclamation can be achieved."

According to the *Miles City Star* (1982), a recently released study, conducted over 6 years in Montana, reaches the same conclusion. The *Star* describes it is "the first long-term study of this type done in the West," and says the results indicate "that native rangeland that is strip mined for coal in the arid Great Plains cannot be reclaimed within the 10-year period required under State and Federal laws." A scientist who worked on the study is quoted as saying "Some of the study sites were revegetated in the early 1970s using the latest reclamation techniques at the time....However, improved current technologies offer greater potential for success. Still, even the latest technologies are not good enough to meet present reclamation standards."

4. The BLM ignores the illegal destruction of aquifers.

There are both Federal and State requirements to insure that the hydrologic balance of aquifers under strip mined lands be restored. It is especially important to agriculture that the near-surface aquifers be maintained. But the BLM and other agencies fail to acknowledge the importance of livestock water not only on and under reclaimed land but on down the flow of the aquifer to off-site and undisturbed lands and watering locations. In the BLM's Powder River EIS (BLM 1980), in which there is a recommendation to lease an additional 1.5 billion tons (since bumped to 2.2 billion) of coal directly affecting tens of thousands of acres of land, the BLM includes such statements as:

> Impacts to the ground water resources would occur *primarily* in the vicinity of the mined area and would have little effect on the *regional* ground water systems. Impacts include removal or modification of aquifers, interruption of ground water flow during mining, modification of flow after reclamation and changes in water quality.

We also read in the same document:

> Removal of aquifers and other strata in the mined areas would permanently destroy 35,000 to 60,000 acres of aquifers (0.002 percent of total aquifers within the region) and alter conditions of ground water occurrence. Removal of perching layers would destroy eight to ten springs and several seeps. Forty-seven to 100 shallow wells would be permanently destroyed.

This total disregard for the significance of water to agricultural production is appalling, and, I believe, illegal as well. To ignore the off-site effects of aquifer destruction or to imply that this destruction is "regionally insignificant" is irresponsible and indicates a grave indifference to the destruction of agricultural productivity.

5. The BLM ignores the negative long-term social implications of mining.

The BLM and other agencies are required to assess the adverse social, economic, and environmental consequences of their actions, but often the BLM not only attempts to understate these negative impacts but editorializes on the advantages of leasing tracts for coal. This not only defeats the purpose of an impact statement but makes a mockery of the process. In a Technical Examination and Environmental Assessment (TEEA) for one Colstrip coal lease application (which should properly show the negative social effects of leasing, presumably on the local ranching community), the BLM (1978) instead showed the negative social impacts of not leasing. First, the TEEA says, "Refusal to lease the application areas would not prevent the continued development at the Rosebud Mine." It then later says that a "shutdown" of the Corette Plant and Colstrip Units I and II would result and the "midwestern customers would also have no recourse but to burn midwest coal . . . or face serious curtailment in operation."

The BLM then reasons:

> Socio-economic efforts of a 'shutdown' would fall into several categories. The most important are lost income, higher unemployment, and decreased tax revenue. Lost income would primarily affect the wage earners and area merchants. However, secondary effects on human service agencies could also be expected. These effects would include: increased aid for dependent children, general welfare, and food stamp applications. It is also reasonable to expect levels of stress to increase as the family income falls. This could lead to additional mental health case loads and also to additional wife and/or child abuse.

How about that! Don't worry about the problems mining coal will cause, because if we don't mine it, people will go crazy and beat their wives and kids!

6. The BLM ignores the negative long-term economic impacts of coal development.

One would expect that somewhere in the TEEA quote above the BLM would reflect upon what will happen in the coal area's economy after the coal boom busts, but it never happens. Instead, the BLM reverses its obligatory position and spouts only the rosy rhetoric of short-term economic benefits of more coal development or the horrible short-term consequences of not having continued coal development. Although this proposed lease sale covers a relatively small area (a part of three sections--"regionally insignificant" as the BLM would point out), we read that not leasing these tracts would cause the following "estimated annual income effect": a payroll loss (including "income multiplier") of $20,612,612 due to a "shutdown" and a direct tax loss of $6,863,370. The BLM's document continues, "Because of limited economic activity in Rosebud County, declines in income, tax revenue, and employment of this magnitude could lead to depression-like conditions in the area." That is as close as the BLM ever comes to predicting what conditions will be like during the eventual bust. But rather than extrapolating these negative figures throughout the Fort Union Region, we see only the tip of the iceberg and only stated in the negative context of "What will happen economically if we don't lease this one small tract of Federal coal."

7. The BLM depends upon the coal industry to decide where coal development will take place, ignoring other values.

First, let's assume a few things, that: 1) a certain amount of coal is "needed"; 2) there are both "good places" and "bad places" to mine; and 3) someone other than the coal companies (who might not be completely objective) should decide which is good and which is bad so that all entities and interests are treated fairly. Okay so far? But is that how it is done? Not by a damn sight! The Secretary of the Interior decides on a target (a somewhat descriptive term) amount of coal to be leased based on recommendations from the Department of Energy, which bases its recommendation upon recommendations from the energy industry; so we have step one. Then coal companies secretly "nominate" (the old way) tracts for leasing or simply divide up the territory between themselves (the new way) and make lease applications. If you think it doesn't work this way, find out how many leases have "competition" in the "competitive leasing scheme." The coal companies then either sit on their leases and speculate, or they begin to develop their leases . . . in a "good place" for them economically. But not necessarily in a "good place" by any other measure. In response to the BLM's Powder River Tract leasing proposals, a reclamation research specialist made these comments (Sindelar 1981):

> I believe that it would be hard to find five poorer tracts for lease consideration given their apparent low potential for reclaimability. Given the soil reconstruction ratings, for example, of 94 percent poor, and suitability of soil material for reclaimability of 75 percent poor or unsuitable, one would conclude that the BLM criteria for site selection did not include potential for successful reclamation. This is a serious flaw, in my opinion, and a flaw that is unacceptable.

The author further states, "Rather than proposing tracts with obvious low reclamation potential, and then counting on OSM to reject them, these tracts should not have undergone further consideration. Perhaps there is some unexplained reason for this questionable procedure." The "unexplained reason" is that industry mines where industry wants to mine, and the BLM will not defy industry's desires even if such desires conflict with the most obvious of BLM's responsibilities.

8. The BLM consistently ignores surface owners' opinions when they are opposed to leasing or mining the Federal coal under their surface.

Despite surface owner opposition to coal development in given coal areas, the BLM continues to move towards development. In the Redwater Management Framework Plan (MFP)(BLM 1980), 58 percent of the landowners in a particular known recoverable coal resource area (KRCRA) were opposed to leasing, and in another KRCRA 53 percent were opposed to leasing, yet in each case not one acre was dropped from further consideration for leasing.

In my area a surface owner who has time and time again indicated her opposition to coal development has been put under terrific pressure because both the BLM and the coal companies keep assuming (apparently) that she will change her mind. She went to the extent of having her attorney contact the BLM and finally drove to Billings to a coal team hearing to protest her surface still being held hostage. The BLM said that there had been an "administrative error" that kept her land in consideration, but the land still continues to be included in the Western Energy long-range mine plan.

9. The BLM refuses to address the cumulative effect of leasing and mining on agriculture.

In its incremental leasing of tracts in a coal development area, such as Colstrip or Decker, the BLM continually and consistently ignores all cumulative impacts, merely citing the inconsequential and the incremental. The BLM will say that the hydrological impacts at Colstrip, for instance, will be just a little bit worse than they already are if another tract is leased, ever acknowledging that the hydrological situation is already horrible. Aesthetically, they find that once there is already mining in "the area," more mining won't make it much worse. There will be an "incremental increase" in "TSP (Total Suspended Particulates), in the Colstrip area" due to additional mining, ignoring the fact that the Colstrip area has for years been a noncompliance area for air quality. The same is true of any geographical area or area of social, economic, or environmental concern.

The NPRC initiated a petition of unsuitability for mining on the Tongue River. But once again, the State and Federal agencies involved refused to declare the area unsuitable even though they acknowledged that the cumulative environmental impacts would probably adversely affect agriculture on Tongue River and Otter Creek.

One of NPRC's contentions was that the mined land could not be economically reclaimed because: The coal market is depressed; the coal is of relatively low Btu value; transportation for coal is not available and will be expensive; the coal is high in sodium (further reducing its value); there is a shortage of readily available topsoil and natural soil material; the overburden is high in clay, sodium and boron, creating a synergistic problem; mining will intercept aquifers. Each of these contentions was examined incrementally and each one was acknowledged as being individually involved, but there was absolutely no effort made to add a few of these problems together into a cumulative analysis. To say that we were discouraged and disappointed is an understatement. We should have known from experience that agencies don't view things logically as they are in the real world, especially if this approach would in any way impede irresponsible coal development and protect agriculture.

Those of us engaged in farming and ranching view coal development with great fears, fears for our way of life, our land, our air, and our water. We have seen "development" and "progress" in our areas in the past from a ringside seat. We well remember what a bonanza the Homestead Era was in our respective area, and we can still see the scars, on the the earth and in humans, that this development created.

I grew up just south of Colstrip and I saw what happened there between 1923 and 1958. In 1969, I was asked to testify at a Governor's Conference on mining. Among other things, I said,

> I have seen millions of dollars worth of coal leave my area with little of it remaining in the area, or even in the state. I have seen thousands of acres of productive land destroyed. . . I have seen people exploited, just as the land was exploited. These people left the area and the state with little evidence remaining to remind us that they were ever here, save for the 'spoil-bank(s)'.

When the present bonanza is over after we run out of coal or find less damaging ways of satiating our energy appetites (for one reason or another the bust, and the withdrawal, are inevitable), will we still have a healthy agricultural industry left in the Fort Union region? And what if we do not? Who will bear the responsibility? Who will bail out the region? And in the grim time when the current "progress" ceases and the "development" crashes by its own weight, who will be able to pick up the pieces and start again? You better hope that it will be good old agriculture, because I don't think at this time you can count on the energy companies, or "the government." I imagine the energy companies will slip away shaking their collective fists at "low prices," "excessive taxes," and "environmental inflexibility," and cry great crocodile tears over the havoc their leaving will cause ("economic considerations and the high costs of labor and governmental red tape leave us no choice but to . . ."). But slip away they will. And the "government" will wring its collective hands and say "What have we done? What shall we do?"

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